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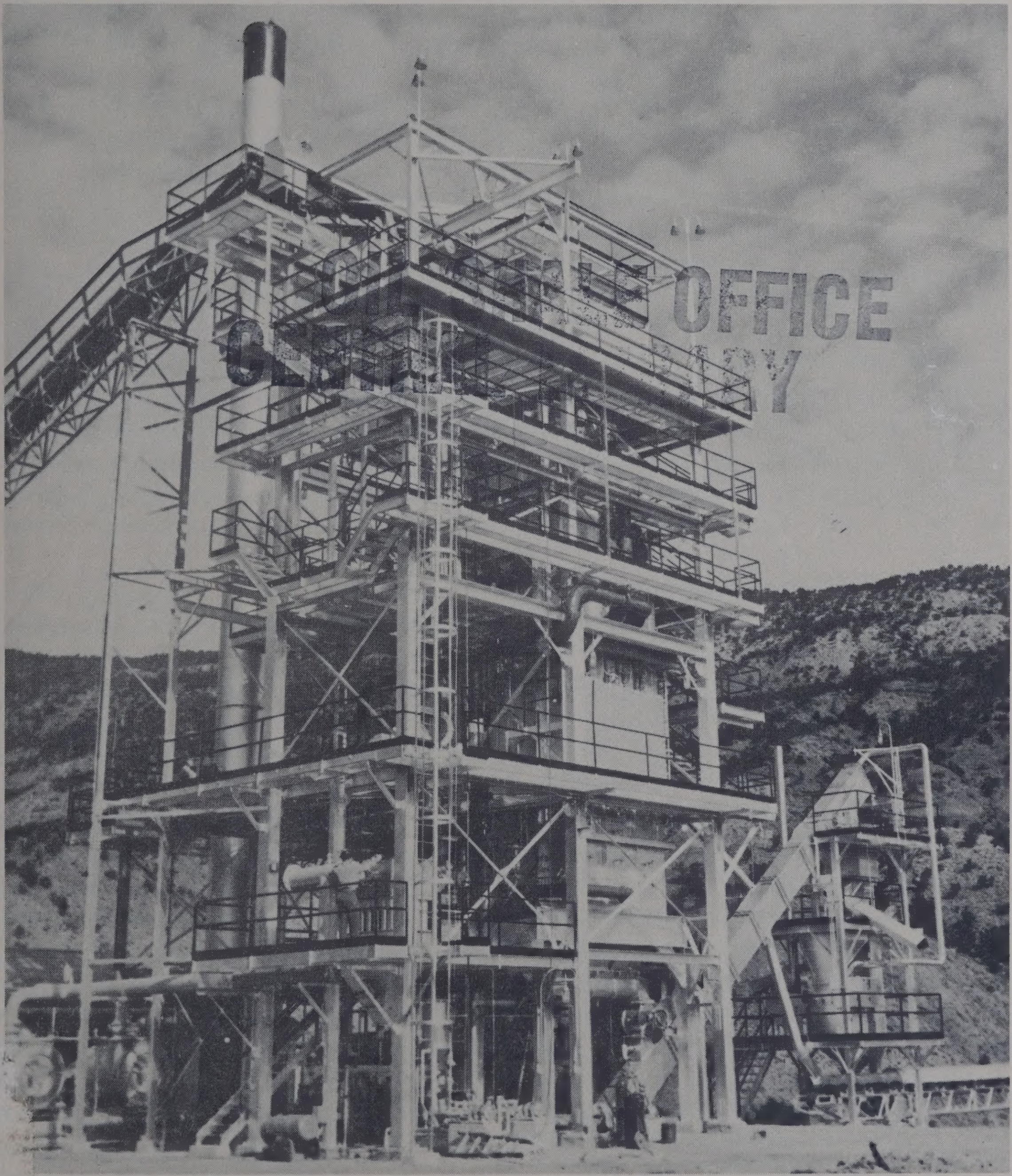
Prospects for
OIL SHALE DEVELOPMENT

Colorado, Utah, and Wyoming



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FOREWORD

In January 1967, the Secretary of the Interior announced a five-point action program for oil shale which represented the Department's views at that time on how the abundant energy potential inherent in the massive oil-shale deposits of the western United States could be developed and utilized most speedily and effectively for the benefit of the Nation and its people. The Secretary's proposed program provided for these actions:

1. Clearing title to public oil-shale lands
2. Blocking up intermingled Federal and private lands by exchange.
3. Issuance of provisional development leases
4. Cooperative research by Government and industry on nuclear explosive fracturing in situ retorting
5. A broad program of Federal research and investigations

In May 1967, the Secretary proposed regulations to govern the leasing of public lands and asked for comments on the proposals. These regulations were designed to complement the announced five-point program in determining the economic potential of oil shale, encouraging the commercial development of oil-shale reserves, and protecting the public interest in such development.

Public response to the Department's proposals has been mixed, with comments being directed mainly to the question of how to proceed rather than whether to proceed. Most of the suggestions received were directed at the specific leasing terms proposed. Need for any program of disposition of the Government-owned shale land at this time also has been questioned.

This summary report attempts to take into consideration comments and suggestions made by members of Congress and interested persons as well as the results of further evaluation of such fundamental issues as the potential for oil-shale development in the near future, the current status and immediate prospects of technology and costs, and the relative merits of alternative courses that might be taken to assure the utilization of domestic oil-shale resources in a manner consistent with the National interest.

The Department invites comments and suggestions on this report within the next 90 days for consideration in its development of a more specific program based upon the findings of this study.

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* * * * * * *

Second Printing -- August 1969

Corrections or revisions include:

Figure 1, p. 12, reprinted in single color

Map of Piceance Creek Basin following p. 16 reprinted in single color and reduced size

Page 53, footnote 1/, table 3, revised by striking the words "working capital or"

Page A-3, table A-3, figures on first line corrected to show Federal acreages; total acreages (private and Federal) were previously shown

1. Introduction

It is estimated by the Bureau of Mines that 81 billion barrels of liquid fuels will be consumed in the period 1966-1980; more petroleum than was produced in the United States during the first 100 years after oil was discovered in 1859. To meet this demand, domestic resources can be developed and utilized in one or more alternative manners: by the discovery, development and improved recovery of natural liquid fuel reserves; by liquefaction of coal; by substitution of other energy sources; and by development of oil-shale resources. As a result, the oil-shale resources again have captured the attention and imagination of both private industry and Government as one means of broadening the resource base to supplement conventional crude petroleum when the need arises.

For many decades there has been no question that a satisfactory liquid fuel can be obtained by heating oil shale. In fact, commercial production of shale oil abroad actually preceded the drilling of the first oil well in the United States by several decades. Shale-oil industries have been established in many foreign countries, and there is commercial production of shale oil today in mainland China and the U. S. S. R.

The oil-shale resources of Colorado, Utah, and Wyoming occur in over 11 million acres. The oil in Green River oil shale with a content of at least 15 gallons per ton, in both private and Federal ownership, may total as much as 1.8 trillion barrels that could be classed as "known reserves." This is more than 60 times the present U.S. "proved reserve" of crude petroleum as estimated by the American Petroleum Institute and represents the potential equivalent of enough oil to meet U.S. needs for hundreds of years.

Interest in the use of this extensive potential source of energy has fluctuated widely and has been influenced substantially by the estimates of proved petroleum reserves at any given time. The initial flurry of industrial attention to oil shale came prior to 1920, with the first signs of concern that domestic petroleum resources might become inadequate. Immediately after World War II an important Federal move toward providing the technological basis for development of an oil-shale industry occurred. The Synthetic Liquid Fuels Act made possible a large-scale research and demonstration effort by the Department of the Interior's Bureau of Mines. This effort was aimed not only at the creation of a new and more economic mining, retorting, and refining technology, but also sought to provide reliable information on the costs of shale-oil production. Since that time, the Department of the Interior has conducted many studies to determine how the western oil-shale resources could be utilized effectively and how the lands containing them should be leased in the public interest.

There are several reasons for the Department's strong and continuing interest in oil shale. Of the more than 11 million acres of land overlying the western Green River Basin oil-shale deposits, approximately 72 percent is Federally owned. This Federal acreage contains nearly 80 percent of the known shale-oil resources in the Green River Basin. It must be managed efficiently as a public resource. The Department of the Interior also has responsibilities such as: bringing within economic reach those natural resources that are in superabundance; conserving natural resources; and assuring an adequate, dependable, and diversely based supply of energy at the lowest cost consistent with other National goals, one of the most important of which is the protection of environmental quality. Efforts to capitalize on one resource must not lead to short sighted actions having unacceptable environmental impacts.

A Federal shale program must assure wise resource utilization and adequate controls to protect the environment as well as resource payments that return a fair market value to the public. In addition, some research areas ordinarily would be undertaken or financed by the Federal Government even in the absence of ownership of the resource since they include important external public benefits such as environmental factors not ordinarily capturable by private interests.

2. Demand and Supply of Energy

A. Demand

Total demand for energy in the United States in 1966 was equivalent to 56 quadrillion British Thermal Units (BTU). During the next 14 years it is estimated that total energy demand will increase at an annual rate of 3.3 percent, reaching 88 quadrillion BTU's in 1980. Table 1 shows the demand for each energy source in 1966, and the Bureau of Mines estimated demand for 1980. Table 2 gives the same information for each energy source expressed in terms of barrels of oil equivalent.

Liquid fuels accounted for 43 percent of the total energy demand in 1966 and are expected to supply a slightly smaller percentage of demand in 1980. Cumulative requirements for liquid fuels for the 15 years--1966 to 1980--are expected to total more than 80 billion barrels. However, no significant liquid fuel deficiencies are anticipated during this period.

B. Supply

Energy resources recoverable at present prices are classified into two broad categories: those currently "known" and those that can be inferred from geologic knowledge but have not yet been discovered. Table 1 shows this information for each fuel and for discovered and undiscovered resources that were estimated (in 1962)

Table 1. - Energy consumption and resources in the United States, 1966-80

	Consumption 1966	Consumption 1980	Consumption 1966-80	Known recoverable reserves	Undiscovered recoverable resources
Crude oil, billion barrels	1/ 4.4	1/ 2/ 6.7	1/ 2/ 81.5	48	200
Natural gas liquids, billion barrels	3/	3/	3/	7	30
Natural gas, trillion cubic feet	16	25	300	268	1,200
Coal, billion tons	0.5	0.7	8.6	220	NA
Uranium, thousand tons U metal	4/ 9	4/ 14	4/ 148	6/ 142+200 7/	6/ 770
billion kwh electricity	4/ 5	4/5/ 657	4/5/ 4,965		
Hydroelectric power, billion kwh	4/ 194	4/ 340	4/ 3,983		
thousand megawatts				8/ 44	9/ 124
Shale oil, billion barrels	0	0	0	10/ 50	10/ 2,000
Tar sands, billion barrels	0	0	0	1.3	NA
Thorium, thousand tons Th metal	0	0	0	6/ 100	6/ 800

1/ Includes natural gas liquids.
2/ Includes any liquids fuels from oil shale.
3/ Included with crude oil.
4/ Production.
5/ Based on AEC's 1966 estimate of 90,000 MWe installed by 1980.
6/ Recoverable at $5-$10 per pound of metal oxide.
7/ Already mined and imported, most of which still exists as uranium.
8/ Developed capacity.
9/ Undeveloped capacity.
10/ See chapter 3 for additional discussion of reserves.

Sources: Consumption, Bureau of Mines Program Statement - FY 1969.
Reserves and Resources, - Energy R & D and National Progress.
Office of Science and Technology, Ali Bulent Cambel - Washington, 1964.

Table 2. - Energy consumption and resources in the United States, in crude petroleum equivalents, 1966-80
(Billion barrels)

	Consumption 1966	Consumption 1980	Consumption 1966-80	Known recoverable reserves	Undiscovered recoverable resources
Crude oil	1/ 4.4	1/2/ 6.7	1/2/ 81.5	48 5/	200
Natural gas liquids	3/	3/	3/	5.1	22.0
Natural gas	2.9	4.4	53.4	47.7	213.5
Coal	2.2	3.3	38.8	993.8	NA
Uranium 4/	1.1	1.7	18.1	41.7	94.1
Hydroelectric power	.4	.5	6.5		
Shale oil	0	0	0	50	2,000
Tar sands	0	0	0	1.3	NA
Thorium	0	0	0	1,183	9,464

1/ Includes natural gas liquids.
2/ Includes any liquid fuels from oil shale.
3/ Included with crude oil.
4/ Calculated at 1 percent utilization of the energy in the fuel.
5/ Combination of estimates by the American Petroleum Institute and that of the Interstate Oil Compact Commission (see text)

to be recoverable at current prices. The fuels that are in surplus supply in the "known" category are coal and nuclear fuels. All fuels, including petroleum, are in adequate supply if "undiscovered" resources are included. Undiscovered resources are calculated on the basis of the best geological information available and the exploration experience of the past.

Petroleum is the energy resource with which shale oil is expected to compete directly. Consequently, a more detailed analysis of the reserve situation for petroleum is fundamental to any appraisal of the potential for oil-shale development. Using the usual definition of "proved reserves" for crude oil, the latest domestic recoverable reserve estimate by A. P. I. as of December 31, 1966, is 31.5 billion barrels. Because recovery technology can be expected to advance, however, and because future drilling will continue to find additional oil in known fields for many years to come, the reserve figures for any given year reflect only part of the amount that eventually will be recovered. On the basis of past experience, it is estimated that the "proved petroleum reserves" will ultimately yield nearly twice the 1966 estimate, or another 31 billion barrels, before they are depleted.

In addition to "proved reserves" the American Petroleum Institute (API) estimated that there are an additional 7.4 billion barrels that can be recovered by injecting fluids into petroleum reservoirs to supplement their natural energy (secondary recovery). The Interstate Oil Compact Commission (IOCC), using a broader definition of recoverable reserves, has estimated that the additional oil that could be recovered economically by fluid injection is 17.5 billion barrels.[1] These resources are a portion of the additional 31 billion barrels which are expected to be added to today's proved reserves.

There are other reserves amounting to as much as 40 billion barrels that are not now economically recoverable but might become so with improved technology or higher prices. Thus, the physical exhaustion of the petroleum resource base is many years away. It is the question of exhaustion of petroleum resources at a given price, however, that must be considered in connection with the timing of shale-oil industry development. Although no precise date can be predicted for the economic exhaustion of domestic petroleum resources, domestic crude oil will continue to supply an important portion of the market beyond the end of this century.

C. Shale Oil as a liquid fuel supplement

The utilization of shale oil is one of several alternative ways by which petroleum reserves can be supplemented. With the vast size and relatively high quality of our indigenous oil-shale resources and the existence of commercial shale-oil industries in other countries, oil shale appears to offer a great potential for meeting future liquid fuel demand and thereby makes these deposits commercially attractive. By bringing into commercial utilization a domestic resource of ample supply, our dependence on foreign sources could be reduced. But, as is the case with any other resource, oil shale must be able to compete economically with petroleum and with alternative methods for providing liquid fuel. Thus, the economics of shale-oil production will determine whether the resource will be used.

---

[1] Known recoverable reserves listed in table 1 combine the API and IOCC estimates. As of this date, these reserves total 49 billion barrels as compared to the 48 billion barrels in 1964. (see table 1)

D. The market for oil in the Free World

An assessment of the need for development of shale-oil resources would be incomplete without mention of the growing demand for petroleum throughout the Free World and the heavy dependence on oil imports. Western Europe and Japan represent a large and growing market for petroleum and by 1980 will be importing some 27 million barrels/day of oil--a quantity 50 percent greater than estimated U.S. consumption in 1980. These imports will come primarily from the Middle East, although these nations also are interested in a diversity of sources, as evidenced by the recent interest of the Japanese in the Canadian tar sands.

American shale oil could constitute an attractive source of supplemental supply to the Free World if development showed promise of a large supply at declining costs in the future. The impact on the security of the Free World and on this Nation's balance of payments could be significant. These possibilities are important reasons for Federal initiative to encourage a competitive oil-shale industry.

3. The Oil-Shale Resource and the Federal Interest

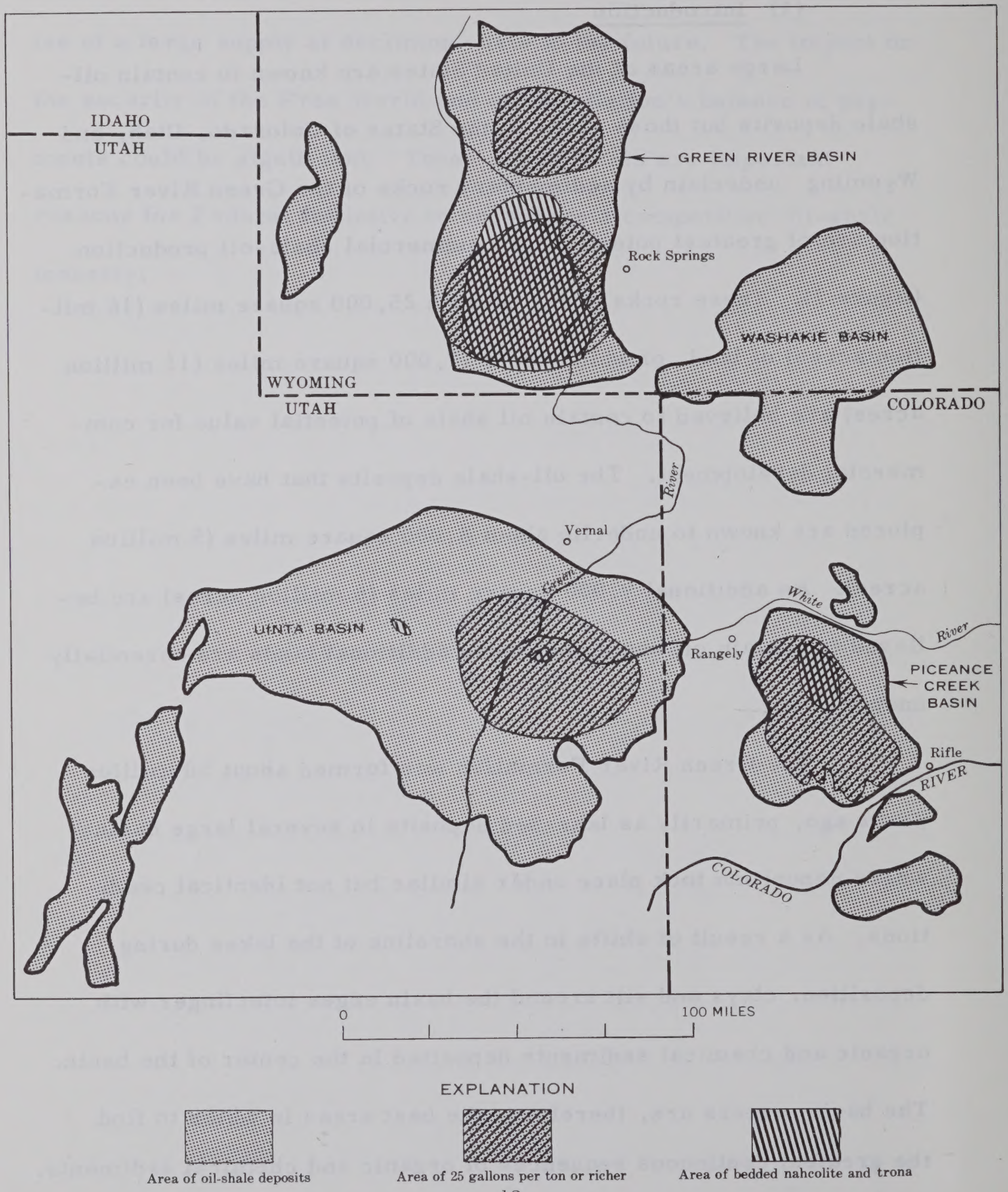
A. Size and ownership

(1) Introduction

Large areas of the United States are known to contain oil-shale deposits but those areas in the States of Colorado, Utah, and Wyoming underlain by sedimentary rocks of the Green River Formation are of greatest potential for commercial shale-oil production (figure 1). These rocks occur beneath 25,000 square miles (16 million acres) of land, of which about 17,000 square miles (11 million acres) are believed to contain oil shale of potential value for commercial development. The oil-shale deposits that have been explored are known to underlie about 8,000 square miles (5 million acres). An additional 9,000 square miles (6 million acres) are believed to contain oil shale, but these additional lands are essentially unappraised.

The Green River Formation was formed about 50 million years ago, primarily as lake-bed deposits in several large basins where deposition took place under similar but not identical conditions. As a result of shifts in the shoreline of the lakes during deposition, clays and silt around the basin edges interfinger with organic and chemical sediments deposited in the center of the basin. The basin centers are, therefore, the best areas in which to find the greatest continuous sequences of organic and chemical sediments.

FIG. 1.—OIL-SHALE DEPOSITS IN COLORADO, WYOMING, AND UTAH



The conditions of deposition were such that most of the organic matter accumulated on the bottom without being oxidized.

The known Green River Formation deposits include shales containing about 590 billion barrels in higher-grade shale (yielding more than 25 gallons per ton and at least 10 feet thick), and about 1,150 billion barrels in lower-grade deposits yielding 15 to 25 gallons of oil per ton. The unappraised resources may contain similar quantities of organic material.

(2) Ownership--Green River Formation

A large amount of Federal oil-shale lands are the subject of private mining claims. For this study, computations of Federal ownership have been made by including as Federal land those areas on which there are unpatented mining claims. The estimates at this time are shown in appendix A, tables A-1, A-2, and A-3, and in figures 2 and 3.

It is estimated that 72 percent of oil-shale lands containing nearly 80 percent of the shale oil is Federally owned. Of the higher grade resources, about 81 percent is in Federal ownership. The quantity of shale oil equivalent in Federal lands of a high quality (more than a 10 foot thickness of shale with an equivalent oil content greater than 25 gallons per ton) is estimated at 480 billion barrels, but nearly 80 percent is in lands on which mining claims have been made and are of record.

FIG. 2.- OIL-SHALE LANDS - GREEN RIVER FORMATION

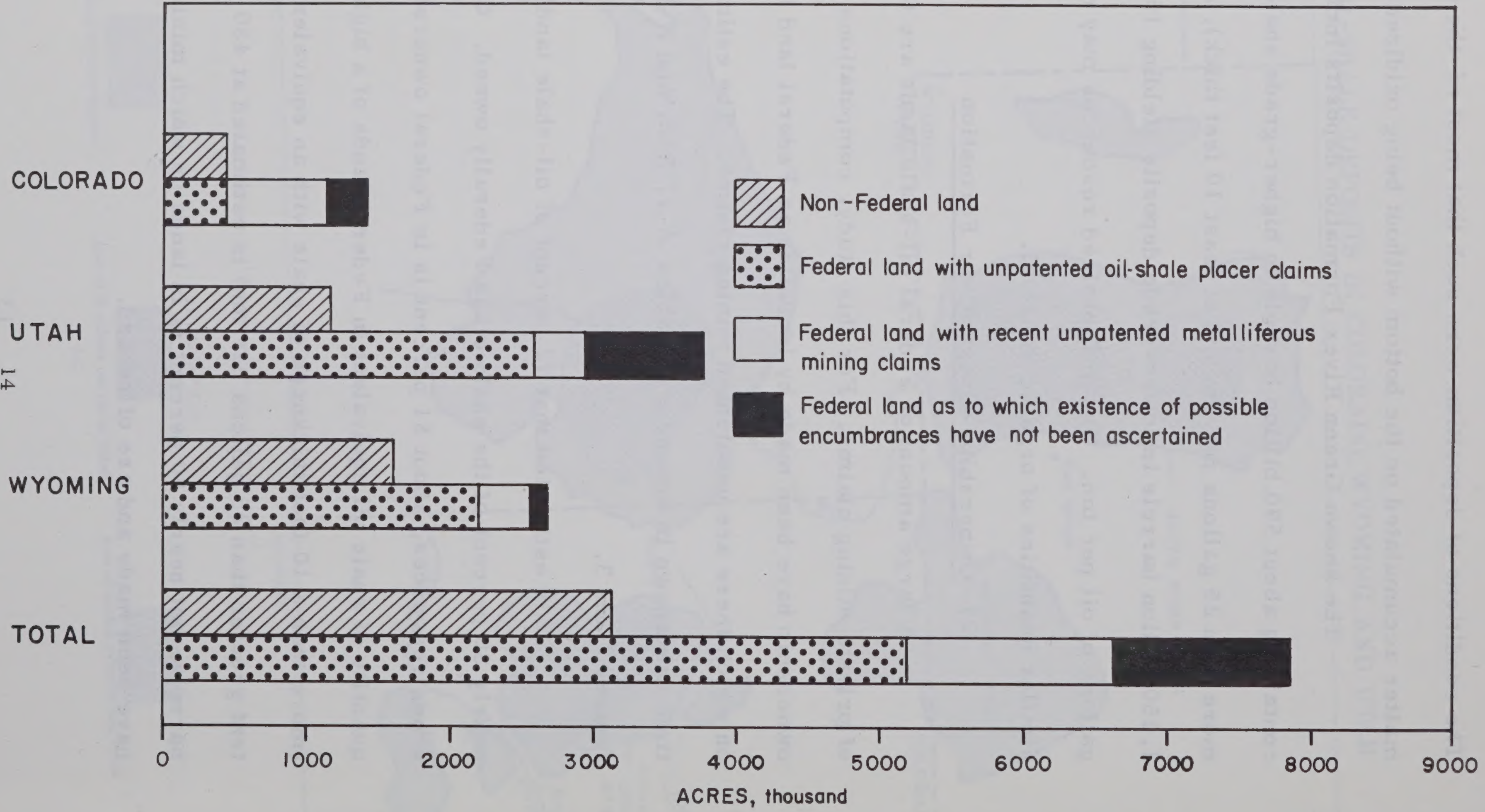
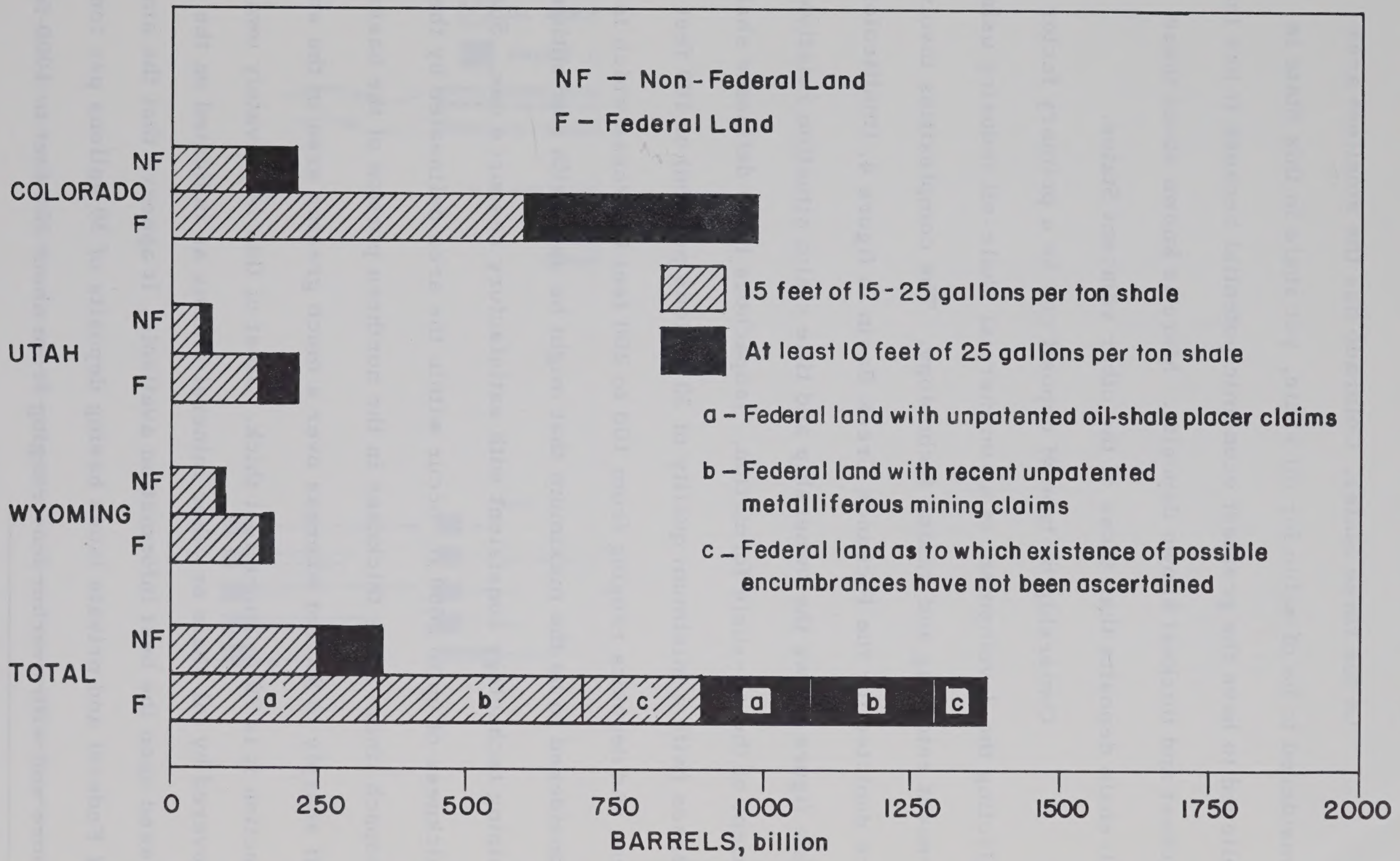


FIG. 3.-BARRELS OF SHALE OIL IN PLACE - GREEN RIVER FORMATION



(a) Colorado

Of the three States, Colorado has the smallest area considered to be of value for oil shale, yet shale in this State is believed to have the greatest economic potential because it has the richest and thickest known deposits. More is known about these oil-shale deposits than those of the other adjacent States.

Ownership by type of deposit can be a primary factor affecting the development of a commercial shale-oil industry using present retorting and mining technology. The complexities involved are depicted for the Piceance Creek Basin in figure 4. (multicolored map).[1] This figure shows the ownership and title claim situation relative to the extent of the oil-shale formation. Isopachous lines delineate shale thicknesses (with a minimum quality of 30 gallons per ton) of 100 feet or less and deposits ranging from 100 to 200 feet thickness which is considered to be the maximum that might be used with conventional mining technology consistent with satisfactory resource use. Shale thickness of up to 2000 ft. occur within the area delineated by the 200 ft. Isopach line. Shale thickness in the northern portion of the basin drops off sharply to 50 feet whereas over a much greater area in the southern section it is 70 or more feet thick. Most of this is privately owned or covered by oil shale or other mineral claims as indicated on the map. Based upon the best information available, it appears that the amount of Federal and private lands having deposits of 30 gallons per ton or more and with overburdens ranging from about 200 feet to 1000 feet are:

---

[1] Map reprinted in single color.

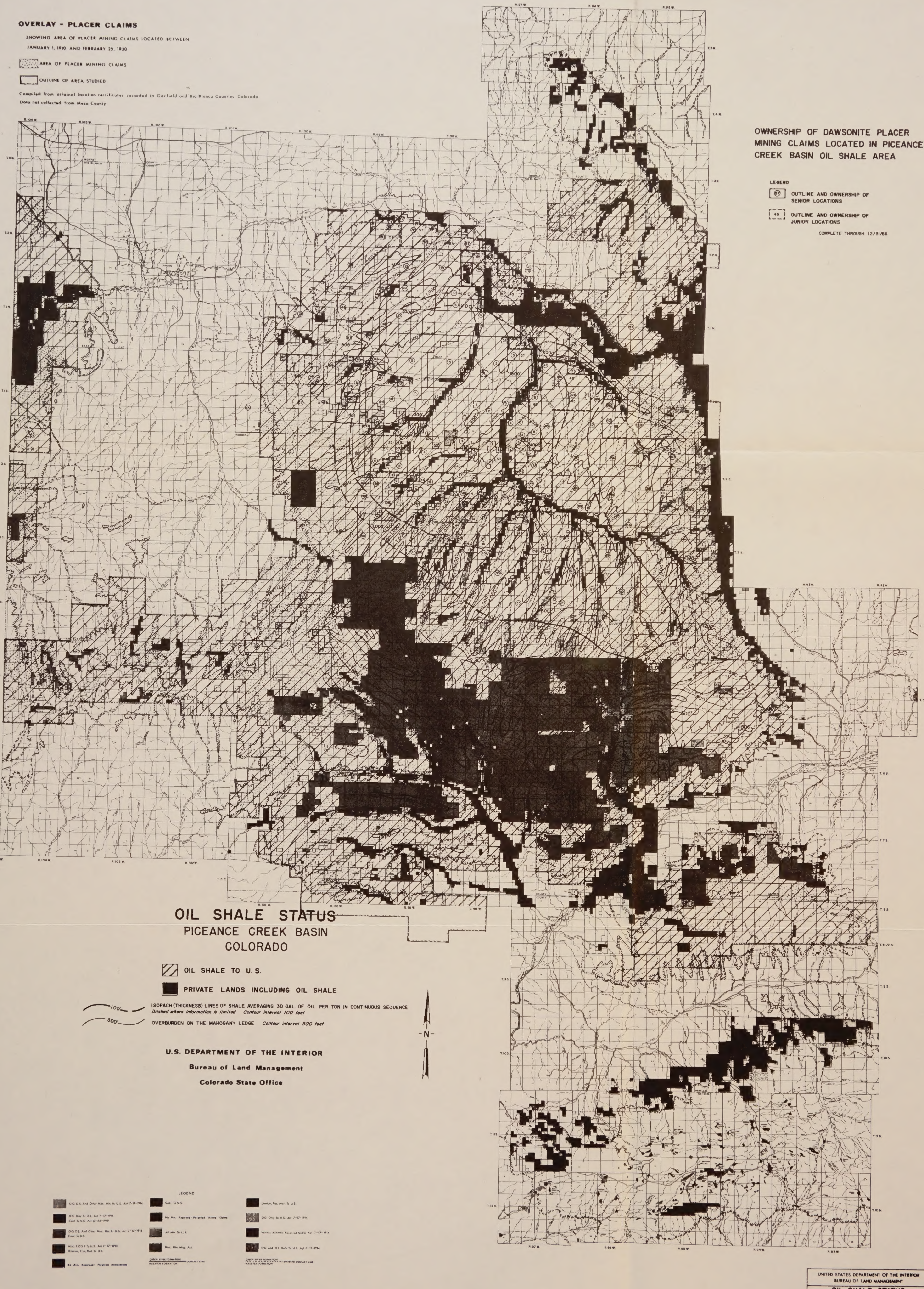
OVERLAY - PLACER CLAIMS

SHOWING AREA OF PLACER MINING CLAIMS LOCATED BETWEEN
JANUARY 1, 1910 AND FEBRUARY 25, 1920

▨ AREA OF PLACER MINING CLAIMS

☐ OUTLINE OF AREA STUDIED

Compiled from original location certificates recorded in Garfield and Rio Blanco Counties Colorado
Data not collected from Mesa County



OWNERSHIP OF DAWSONITE PLACER MINING CLAIMS LOCATED IN PICEANCE CREEK BASIN OIL SHALE AREA

LEGEND

(57) OUTLINE AND OWNERSHIP OF SENIOR LOCATIONS

45 OUTLINE AND OWNERSHIP OF JUNIOR LOCATIONS

COMPLETE THROUGH 12/31/66

OIL SHALE STATUS
PICEANCE CREEK BASIN
COLORADO

▨ OIL SHALE TO U. S.

■ PRIVATE LANDS INCLUDING OIL SHALE

ISOPACH (THICKNESS) LINES OF SHALE AVERAGING 30 GAL. OF OIL PER TON IN CONTINUOUS SEQUENCE *Dashed where information is limited Contour interval 100 feet*

OVERBURDEN ON THE MAHOGANY LEDGE *Contour interval 500 feet*

U.S. DEPARTMENT OF THE INTERIOR

Bureau of Land Management

Colorado State Office

LEGEND

■ O.G., O.S., And Other Misc. Min. To U.S. Act 7-17-1914

■ O.G. Only To U.S. Act 7-17-1914 Coal To U.S. Act 6-22-1910

■ O.G., O.S., And Other Misc. Min. To U.S. Act 7-17-1914 Coal To U.S.

■ Misc. (O.S.) To U.S. Act 7-17-1914 Uranium, Fiss. Mat. To U.S.

■ No Min. Reserved - Patented Homesteads

■ Coal To U.S.

■ No Min. Reserved - Patented Mining Claims

■ All Min. To U.S.

■ Misc. Min. Misc. Act

GREEN RIVER FORMATION / WASATCH FORMATION CONTACT LINE

■ Uranium, Fiss. Mat. To U.S.

■ O.G. Only To U.S. Act 7-17-1914

■ Various Minerals Reserved Under Act 7-17-1914

■ O.G. And O.S. Only To U.S. Act 7-17-1914

GREEN RIVER FORMATION / WASATCH FORMATION INFERRED CONTACT LINE

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

OIL SHALE STATUS
PICEANCE CREEK BASIN
COLORADO

DESIGNED MGC
DRAWN AA&MP
CHECKED MGC
RECOMMENDED J. Elliott Hall
RECOMMENDED
MINING ENGINEER
APPROVED
COLORADO STATE DIRECTOR
SCALE 1/4" = 1 Mile
DATE NOVEMBER 1966
SHEET 1 OF 1
DRAWING NO.

Ownership of Oil-Shale Lands in Colorado
(Exclusive of 40,000 Acre Naval Reserve)

	Federal (Acres)		Private (Acres)	Total (Acres)
Shale Thickness	Clear Title	Mining Claims		
0 to 100 feet	69,000 1/	315,000 (largely oil shale)	306,200	690,200 4/
100 to 200 feet	20,000 2/	110,000 (mostly dawsonite)	21,700	151,700
Over 200 feet	3,000	145,000 (nearly all dawsonite)	20,600	168,600
	92,000 3/	570,000	348,500	1,010,500

1/ It is estimated there are 2 areas in the northern part of the basin that would be of sufficient size to support commercial production operations.

2/ It is estimated that there would be one area that would be of sufficient size to support a commercial production operation.

3/ Clear title Federal ownership is in scattered, isolated, small tracts that would not support commercial production. However, some might be suitable for development in conjunction with adjacent private holdings.

4/ Of this amount approximately 200,000 acres have oil shale thickness of 50 feet or less.

The land held in private ownership is largely at the outcrops of the deposits or along some streams and valleys within the Colorado Piceance Creek Basin where some of the private ownership of deeply buried deposits was achieved through homesteading. Federal ownership of the outcropping deposits is very small, probably about 1 percent of the total Federal ownership (exclusive of Naval reserves).

A cross section showing thickness of the shale and overburden in the Piceance Creek Basin is shown in figure 5. The oil-shale deposits become increasingly thick and more deeply buried toward the center of the basin. At the Basin center the overburden varies from 500 to 1,600 feet in depth and shale thicknesses of about 2,000 feet are found. Shale quality varies from 10 to 60 gallons per ton, depending on the horizon, and averages about 25 gallons per ton. Near the center of the Basin, there are some zones 50 to 200 feet thick that yield 40 gallons per ton. There are estimated to be about 50,000 acres that contain shale beds averaging from 35 to 40 gallons per ton in thicknesses of 50 feet or more.

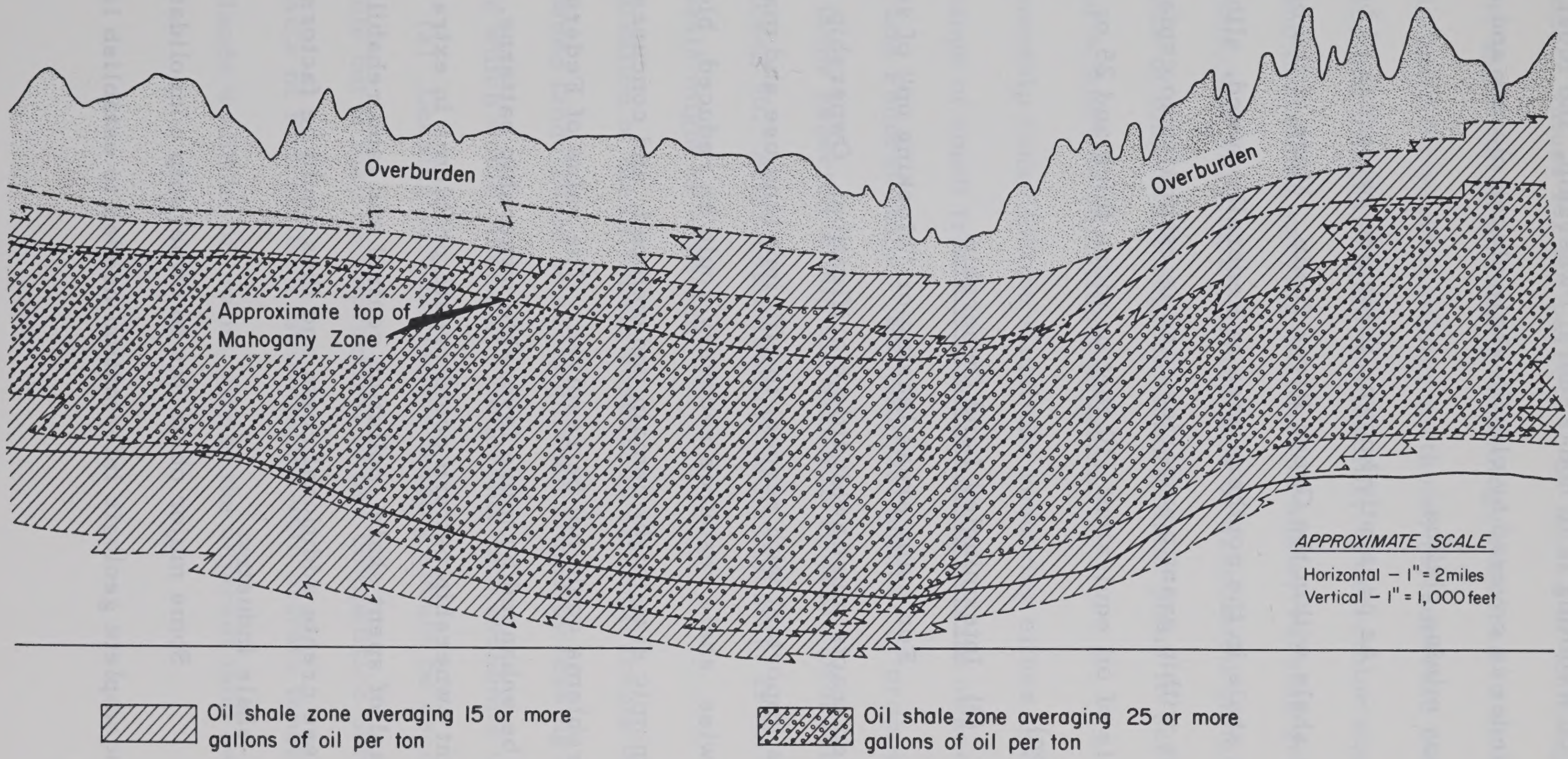
(b) Utah

Next to Colorado, Utah contains the best of the evaluated oil-shale deposits and the most extensive deposits of all three States. The best of the Utah deposits lie in the east-central part of the Uinta Basin. They may be as much as 700 feet thick and their depth varies from outcrops at the southern edge to several thousand feet below the surface near the Basin's center. The percentage of Federal ownership of shale lands in Utah is slightly less than in Colorado.

(c) Wyoming

So far as is known, the oil-shale deposits in Wyoming are not as rich as those in Colorado or Utah. Much of the oil-shale

FIG. 5. - CROSS SECTION NEAR CENTER OF PICEANCE CREEK BASIN


Overburden
Overburden
Approximate top of Mahogany Zone
APPROXIMATE SCALE
Horizontal – 1" = 2miles
Vertical – 1" = 1,000 feet
▨ Oil shale zone averaging 15 or more gallons of oil per ton
▩ Oil shale zone averaging 25 or more gallons of oil per ton

lands of Wyoming is in non-Federal ownership, and most of the remainder is covered by old oil-shale placer claims and new metalliferous mining claims.

As presently known, there are two areas of better-grade shale within the Green River Basin. More of the better-grade shale in the northern area is Federally owned, although part of it is within grant boundaries, and is estimated to contain 30 billion barrels of oil equivalent (10 feet or more thick and 25 or more gallons per ton).

(3) Intermingled Land Ownership

For many areas leasing or "blocking up" of small intermingled tracts must await title clarification. Ownership patterns can be important with respect to efficient land use and management, otherwise shale resource recovery could be reduced, blocks of uneconomic size might remain undeveloped, and concurrent surface-use problems could not be resolved. The value of Federal lands could be enhanced by more favorable ownership patterns. The present ownership pattern could create problems in extraction, disposal of spent shale, pollution control and land rehabilitation. All these create additional costs and thus could be factors in delaying an oil-shale industry.

Some major obstacles to ownership consolidation are: (1) incomplete geologic information needed to establish land and mineral resource values for the parcels to be leased or exchanged; (2) incomplete information on mining technology required to establish economic units for various mining methods; (3) separate ownership of surface and mineral rights; (4) inability to determine equal values for land containing varying qualities of shale, varying geologic conditions, and varying concentrations of associated minerals; and (5) absence of long-range regional management plans to serve as a basis for a land-use adjustment program.

Ownership consolidation situations requiring either leasing or land exchange of small tracts may exist among private owners, State lands, and Federal lands. The potential number of proposals for Federal lands expected within the next 5 to 10 years probably would not exceed 50. After establishment of an industry, from 100 to 200 proposals might be expected.

Utilization of the oil-shale resources on small tracts of Federally owned lands could be accomplished either by leasing or by exchanges which would "block up" ownership into economic units.

(a) Leasing -- Competitive leasing should be used where possible but it may be impractical to use competitive bidding for small tracts of Federal land intermingled with private lands where such lands would be of value only to the adjacent land owner.

Until there is sufficient commercial production from formations of a similar nature, a fair market value would be difficult to estimate. However, provision for such leasing, at an appropriate time when values can be estimated with a reasonable degree of accuracy, should be included in the Federal leasing policy.

(b) Exchanges -- Ownership consolidation may be more appropriate where intermingled Federal lands could be exchanged for privately owned lands of equal or greater value. This would have the advantage of avoiding the problems of estimating explicit oil shale fair market values and of lack of competition as the exchange would be on the basis of comparable resource considerations. Such action could eliminate possible barriers to the effective development of these privately owned resource blocks. Similarly, it could consolidate Federal ownership into suitable economic units either by elimination of small internal tracts of private holdings or by extending the overall size of Federal holdings.

B. Status of geologic information

Approximately 650 drill holes have penetrated into or through the oil-shale bearing rocks of the Green River Formation. These have been drilled mostly by private individuals or companies. About

250 of these are core holes drilled to test for oil shale. Most have been drilled in attempts to validate oil-shale claims or appraise oil shale in privately owned deposits. Also, about 250 oil and gas test wells have penetrated the Green River Formation. The rock cuttings from such wells have yielded general knowledge of the character and quality of the oil shale, but the data so obtained are insufficient for accurate appraisal of the shale. About 150 holes have been drilled to test sodium minerals such as trona and nahcolite in the oil shale. Generally, the cores so obtained are limited to the sodium mineral-bearing beds and are incomplete as tests of oil shale. Of the total past drilling in the Green River Formation, only about 50 core holes can be considered adequate tests of the complete oil-shale sequence in the areas of the better oil shale.

The best information is available for the oil-shale deposits in Colorado, followed in order by Utah and Wyoming.

Reconnaissance mapping of about 1.8 million acres in Colorado and 1.5 million acres in Utah has been completed. In addition, detailed geologic mapping of the oil-shale-bearing rocks of the Green River Formation has been completed on modern topographic quadrangle maps for about 10 percent or 1,700 square miles of the total 17,000 square miles of oil-shale-bearing areas. The remainder of the area should be investigated and mapped in detail to determine the extent, thickness, and depth of the oil shale. Most of the detailed mapping has been conducted in the outcrop areas of the oil shale. The thicker and richer deposits, which occur in the central areas of the oil-shale basins, are largely unmapped. Geologic mapping of the central basin areas should be coordinated with core drilling and sample analyses to complete the delineation of the better deposits.

The bedded sodium minerals in the oil-shale sequence have been vigorously explored and developed by the private sector in the Green River Basin, Wyoming, where more than 100 core holes have been drilled to test the trona beds in the shallower parts of the basin. About 20 core holes have been drilled where nahcolite, salt, and dawsonite occur in the Piceance Basin, Colorado, and a few holes have revealed sodium minerals in the oil shale of the Uinta Basin, Utah.

C. Need for geologic investigations

Adequate geologic information is essential to the inventory, evaluation, and use of Federally owned resources in accordance with sound business principles and natural resource management. Without such information the quality and other physical features of the oil shale and associated minerals cannot be known sufficiently to supplement resources development plans or to estimate accurately a fair market value. These gaps in information include not only the total amount of the shale oil and minerals but also the quality of the reserves and the geologic setting in which they are found. These factors have a major economic impact on the cost of extraction and subsequent processing.

Geologic information is of value not only to the Government but also to potential bidders. The more certain the geologic information, the fewer risks there are to the bidder and the less he needs to discount his bid to reduce risk.

If "blocking up" of ownership is necessary, geologic information is essential to assure equitable exchange of shale lands between public and private owners. Unless the lands to be exchanged are contiguous, the valuation probably will require core drilling, sampling, and analysis of the shale and associated minerals.

Available information concerning associated minerals is limited, particularly on the Federally owned lands of the Piceance Creek Basin. More detailed information is required to provide a basis for estimating as to whether these minerals can be mined and processed economically from horizons of essentially oil-shale-free sodium deposits or as to the quality of the deposits where the minerals are commingled with the oil shale.

Detailed geologic data also are required to assure professionally based conservation and environmental controls and to establish approved mining plans. Improved hydrologic information on ground water and aquifers is needed for formulating underground mining plans in areas where water may present difficulties. That information also will be used to define potential water pollution and water supply problems and indicate methods by which they can be avoided.

In areas where nuclear in situ experiments are expected to be conducted, hydrologic information will be needed to establish the magnitude of problems that may arise from underground water flowing into a nuclear chimney during retorting, as well as potential environmental problems associated with radioactivity contamination of ground waters from the use of the nuclear device.

D. Associated minerals in oil shale

In addition to potential oil resource, these lands also contain other minerals which may be of value. Such minerals may occur as a part of the primary oil-shale complex, be primarily other minerals but with some kerogen [1/] content, or be separate deposits outside the shale formation. The principal associated sodium minerals having the most significant potential values for consideration include trona (a sodium bicarbonate/sodium carbonate complex), nahcolite (sodium bicarbonate), dawsonite (sodium aluminum dihydroxy carbonate), halite (sodium chloride), and shortite (sodium

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[1/] A bituminous material occurring in oil shale which yields oil when heated.

calcium carbonate). Considerably more resource and processing technology information is needed before their extent and potential economic value can be estimated. Other minerals associated with, or that are above or below, the oil shale are asphaltic hydrocarbons, tar sands, petroleum, and natural gas. The known distribution of the trona and nahcolite associated with oil shale in the three-State area is portrayed in figure 1. Dawsonite and an aluminum hydroxide mineral occurring as matrix of the oil shale are not shown in this figure because information on the deposits of these minerals is very limited.

Preliminary estimates for 150,000 acres in part of the central portion of the Piceance Creek Basin in Colorado show 30 billion tons of nahcolite in place, containing the equivalent of 19 billion tons of soda ash. For dawsonite in the same area, the preliminary estimate is 27 billion tons containing 9.5 billion tons of alumina (Al_2O_3). Other minerals in the oil-shale beds include extensive bedded deposits of trona and halite (sodium chloride). In the Green River Basin, Wyoming, 24 trona beds have been identified; they are estimated to contain 67 billion tons of trona. An additional 36 billion tons of mixed trona and halite are estimated to be contained in 14 other beds in the same Wyoming area. The trona is mined and converted locally to soda ash.

E. Title clearance issues

(1) Background

Under the 1872 mining law,[1] any citizen of the United States (and any noncitizen who has declared his intention to become a citizen) who makes a discovery of a valuable mineral deposit on the public lands of the United States may work that deposit for his own benefit. One who validly locates a claim (a "locator") is entitled to exclusive occupancy of the claim if he annually performs assessment work in the amount of $100; and may remove and sell the minerals produced from the claim without accounting to the United States for any of the proceeds of the sales. He is not required to seek a patent to the claim (a conveyance of the United States' rights in the land), but may obtain a patent if he has performed $500 worth of work on each claim, paid for its survey (except for placer mining claims located by legal subdivision), paid $2.50 per acre (for a placer claim), and can demonstrate that he has complied with the law.

There is no limit to the number of claims that any one person may locate.

(2) Pre-1920 oil-shale mining claims

During the period from 1915 to 1920 the demand for petroleum in the United States increased and the rate of discovery of new oil fields declined. Fear of crude oil shortage developed and this, together with oil-shale studies published by the U.S. Geological Survey, stimulated interest in oil shale. As a result, more than 36,000 placer mining claim locations were filed for oil shale in this period.

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[1] Act of May 10, 1872, as amended, 30 U.S.C., §ec. 22 et. seq. (1964)

The Mineral Leasing Act of 1920 [1/] superseded the 1872 mining law as to deposits of coal, phosphate, sodium, oil shale and certain other minerals by providing that they would thereafter be subject to disposition only by lease and would no longer be locatable under the 1872 law. The 1920 Act did not extinguish all unpatented mining claims on lands known to be valuable for such minerals, and in existence on the date of the Act, but rather preserved any such claims as were valid and were thereafter maintained in compliance with the law under which they had been initiated.

The Department in the late 1920's and early 1930's instituted proceedings to cancel a large number of mining claims for failure to perform annual assessment work. Many claims were cancelled, and most of their owners neglected to appeal to the Secretary, or if they did, they neglected to appeal from his decision to the courts.

In 1935 the Supreme Court held that the Department could not cancel claims for failure to perform assessment work. [2/]

[1/] Act of February 25, 1920, as amended, 30 U.S.C. 181 et. seq. (1964)

[2/] Ickes v. Virginia-Colorado Development Co., 295 U.S. 639 (1935)

In the late 1950's and early 1960's applications were made for patents to claims cancelled in decisions rendered in the earlier contests which were not thereafter appealed for failure to do assessment work. The Department refused to consider the applications and, while it acknowledged that the earlier decisions may have been based upon an erroneous legal theory, held that after 30-odd years the applications would be denied on grounds of finality of administrative action, estoppel by adjudication, and res judicata.[1] The applicants sought relief in the courts to compel the Secretary to consider their applications and, in some cases, to compel him to issue patents. The United States District Court in Colorado has rendered judgment that the Department may not rely on the old cancellations in disposing of the pending applications. That judgment has been appealed by the Government, and is now pending in the United States Circuit Court of Appeals for the 10th Circuit.

In 1964 the Bureau of Land Management instituted proceedings in test cases against certain pre-1920 oil-shale claims. These cases are the first of a series of test cases which will be filed by the Department for the purpose of establishing a comprehensive set of legal principles for judging whether pre-1920 oil-shale claims are valid or invalid. The trial of the first of these cases before a hearing examiner of the Bureau of Land Management has been concluded. When final briefs are filed, the cases will be ready for decision. A central issue in the pending cases is whether the claimants have established that oil shale can be the basis of a "discovery," i.e., whether a person of ordinary prudence would have been justified in the further expenditure of labor and means with a reasonable prospect of success in developing a valuable oil-shale mine. The Government's position in the contest proceedings is that the state of technology and economics was (and is) such that in 1920 (and subsequent thereto) the requirements of the prudent man rule were not met by the claimants. If the outcome of that case is favorable to the United States, there will be little, if any, basis for the assertion that any pre-1920 oil-shale claims are (or ever were) valid.

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[1] Union Oil Company of California, et al., 71 I. D. 169 (1964)

It must be assumed that if the decision is adverse to the claimants, an appeal will be taken. Even with reasonably prompt consideration by the courts, all issues may not be finally resolved for several years. If the legal principles laid down in these cases and other test cases establish the validity of the pre-1920 claims, the claimants will be entitled to receive patents from the United States conveying the entire interest of the United States in the affected lands and not merely the title to the oil-shale deposits.

(3) Post-1920 claims

As noted above, the 1920 Mineral Leasing Act constituted a withdrawal of oil-shale lands and deposits from location under the mining law. Another effect of that Act was that it withdrew (or segregated) the lands known to be valuable for oil shale from entry and location under the mining law. By Executive Order No. 5327 of April 15, 1930, the lands containing oil shale were withdrawn from leasing or other disposition.

In 1954 the passage of the Multiple Mineral Development Act [1/] permitted the location of mining claims for separate deposits of locatable minerals in lands known to be valuable for leasable minerals. Since the Mineral Leasing Act had provided that any such lands were not open to mining location and the 1930 withdrawal had been made under authority of the Pickett Act, as amended, [2/] (which did not authorize withdrawal of lands from location for metalliferous minerals), the effect of the 1954 Act was to remove the 1920 Act as a bar to the location of separate deposits of metalliferous minerals in oil shale lands.

In March of 1966, apparently as the result of a local news article indicating the presence of aluminum in dawsonite, a sodium aluminum carbonate, in the Piceance Creek Basin oil-shale deposits in Colorado, a claims rush began. Location certificates purporting

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1/ Act of August 13, 1954, 30 U. S. C. §§ 521-531 (1964)
2/ Act of June 25, 1910, as amended, 43 U. S. C. §§ 141-142 (1964)

to record discoveries of deposits of locatable minerals in oil-shale lands in Colorado, Utah and Wyoming were filed in local county recorders' offices for over three million acres of land. In January 1967 the lands were closed to all mining location.

Without ascertaining the facts as to each of the recent claims, it is not possible to determine whether they meet the requirements of the mining laws. Among these requirements are compliance with state location and recordation procedures; exposure of a locatable mineral within the boundaries of the claim; and the existence of facts sufficient to meet the prudent man test.

To the extent that claimants assert that the locatable mineral deposit is of dawsonite, no rights are acquired by the mining locations since dawsonite is a carbonate of sodium and therefore is a leasable rather than a locatable mineral. 1/ Moreover, it appears that dawsonite may occur only as a finely interspersed constituent of the rock known as oil shale. 2/ If any of the claims were determined to be valid, the claimants would be entitled to patents conveying the right to

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1/ Wolf Joint Venture et al., A-30978, 75 I. D. ______ (May 2, 1968).

2/ This question is directly presented by the application for sodium preference right leases which are the subject of the decision cited in footnote 1. That decision directed that hearings be afforded to the applicants who claim to have discovered valuable sodium deposits (dawsonite and nahcolite) in the oil-shale lands of the Piceance Creek Basin during the life of their sodium prospecting permits. Among the issues to be considered are whether the dawsonite and nahcolite minerals are themselves constituents of oil shale, whether the dawsonite can be removed without removal of the kerogen-bearing rock, and whether in the circumstances the sodium rather than the oil-shale leasing provisions of the Mineral Leasing Act can be considered to be applicable. Also at issue are questions going to the economic feasibility of mining the alleged sodium deposits.

all mineral deposits, except leasable mineral deposits expressly reserved to the United States and the use of the surface as set forth in the Multiple Mineral Development Act.

The presence of the large number of post-1920 claims raises the question whether the lands can be managed properly without adjudication regarding the validity of all the claims. The likelihood of validation of such claims is remote but it is essential to seek an early determination of validity so that clear title can be established. In 1967 the Department initiated its first contest involving four mining claims believed to be located for dawsonite. A decision on the merits was not reached, however, for the parties involved relinquished all right, title, and interest in the claims to the United States on April 26, 1968. The Department is now preparing to contest a second group of claims believed to have been located for dawsonite.

(4) Number of claims

Based on a detailed analysis in Colorado, old records and preliminary review in Utah and Wyoming, the estimated number of claims in the two major categories (pre- and post-1920) are:

	Number of claims			
	Colorado	Utah	Wyoming	Total
A. Pre-1920 oil shale	9,000	15,000	12,000	36,000
B. Post-1920				
Dawsonite	3,450	1,750	--	5,200
Platinum	2,150	--	--	2,150
Gold, gilsonite, uranium, other	600	3,550	5,000	9,150
TOTAL	15,200	20,300	17,000	52,500
C. Shale oil, billions barrels[1]	820	150	120	1,090

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[1] See Appendix A, Table A-3

F. Federal interests

(1) Introduction

A Federal energy goal is to assure an adequate supply of energy for present and future needs at reasonable costs in a manner consistent with other national goals.

In addition to oil shale, the United States has substantial and diversified energy resources. However, as reserves diminish, there may be supply or cost problems, especially for petroleum and natural gas. Oil-shale resources on public and privately owned lands can be a source of liquid petroleum, at domestic crude oil price, if it is economically competitive with other alternatives, such as improved secondary recovery from existing oil wells, or conversion of coal to liquid fuels.

(2) Resource management

In addition to the Department of the Interior's energy programs to identify future problems in supply and demand, to facilitate selection among alternative solutions to these problems, and to assure a dependable supply of energy at appropriate social and economic costs, the Department, as manager of the Federally owned oil-shale resources, has the direct responsibility to manage all natural resources on Federal lands so that they contribute as effectively as possible to the satisfaction of public needs for energy and other resource benefits.

(3) Technology and development

Oil-shale processing technology in the United States is currently limited almost exclusively to experimental surface retorting and to conventional room-and-pillar mining methods. A commercial-scale retorting plant has not been built in the United States. Actual economic feasibility can only be tested by the construction and operation of a commercial-scale plant.

Since most of the deposits for which the tested mining technology is well suited (at reasonable recovery of the resource and at lowest mining costs) are in private ownership, development of this resource could be undertaken by the private sector without use of Federal land if other significant factors (Continental Shelf leasing, import restrictions, tax provisions, etc.), remain generally as they are. The study indicates that no serious barriers exist for private development other than investing in a high technologic risk venture.

(4) Federal initiative

There has been, and will continue to be, a need for Federal initiative and participation in the development of oil-shale mining and processing technology to assure that the potential of this resource is realized, particularly in view of the latent values of the massive Federal holdings. Federal efforts, of course, must be coordinated fully with those of industry to assure that each properly fulfills its respective responsibilities.

The public lands contain nearly 80 percent of the oil-shale resource, most of which is in deep, thick deposits. The thick deposits are not suitable for room-and-pillar mining unless relatively few horizons in the deep thick seams of oil shale are mined. Such mining could leave most of the oil shale unrecovered. If an attempt is made to increase recovery significantly from these thick deposits (up to 2000 feet of shale) mining costs would be increased appreciably. The Federal Government, as landowner, has a major responsibility for ensuring the economic development of this type of deposit consistent with sound multiple-use, natural-resource policies. In addition, the Federal initiative should include an active program to make Federal lands available on a competitive basis as they are needed.

The potential large-scale resource utilization combined with the development of a large industrial complex also offers excellent opportunity for the Federal Government to work cooperatively with States, local governments, and private industry in development of the resource potential in the best public interest.

This may require varying degrees of Federal initiative such as direct Federal research, joint research ventures with industry, participation in or partial support of private research, and other industry encouragement, as appropriate, to obtain the desired resource development.

(5) Future technology

Since commercial oil production from oil shale will be by private industry, major improvements in technology beyond those needed for initial development should be accomplished by the private sector. Nevertheless, where major new technology must be developed, it may be necessary for the Government to assume an active role.

(6) Title clearance

Since a factor relevant to development of the publicly owned resource is clarification of title to the oil shale lands, this should be accomplished as rapidly as possible to protect both Federal and private interests. So long as uncertainty remains, private investment is improbable and leasing of Federal lands or "blocking up" of land ownership to form economic production units is not possible. Rights to ingress or egress, development of necessary community and support facilities, management of other surface and subsurface resources, and similar necessary actions may continue to present major problems where land titles remain uncertain.

(7) Geologic investigation

Adequate geologic knowledge of Federal lands is essential for development and utilization of the oil-shale resource. Both the quantity and quality of this resource and the minerals associated with it can be determined with considerable accuracy. For Federal lands the funding of this investigation is a Federal responsibility.

(8) Associated minerals potential

Federal lands also may have potentially significant values for other minerals. Particular attention should be directed to exploring the potential for economic recovery of those minerals that are an integral part of oil-shale formations as such recovery could have an impact on the economics associated with resource utilization. Within known existing technology, these associated minerals do not appear to have economic value.

(9) Summary

The Federal Government must manage its lands and related resources in the public interest and play a major role in geologic investigations and in development of applicable technology. It must manage the oil-shale resource so as to ensure the best resource use consistent with National energy goals, and in harmony with all related resource and environmental factors, assure a fair market value return to the Government, avoid financial "windfalls," maintain appropriate competitive climate for industry's use of the resources, and avoid waste.

4. Technology and Economics of Oil Shale Production

A. Status of oil-shale technology

(1) Oil-shale processing systems

The primary factor inhibiting commercial development of the oil-shale is the cost of production relative to costs of alternative sources for meeting liquid petroleum needs. Technology has been developed for surface retorting that may be economic for commercial production. However, such technology has not been proved by actual operation of a commercial-scale plant in the United States. Conventional mining methods have been tested and are well suited for mining relatively thin shale seams. There are sufficient deposits of this nature now in private ownership to support commercial production if economically feasible technology is available or can be developed. This section describes existing and potential mining and retorting systems that may be developed and applied to the various types of shale formations with sufficient oil content to support commercial utilization.

The best available engineering information was used in estimating the costs of mining, retorting and semirefining. In some instances, however, data were incomplete and conservative judgments were made with respect to the values to be assigned to certain process variables under full scale operations.

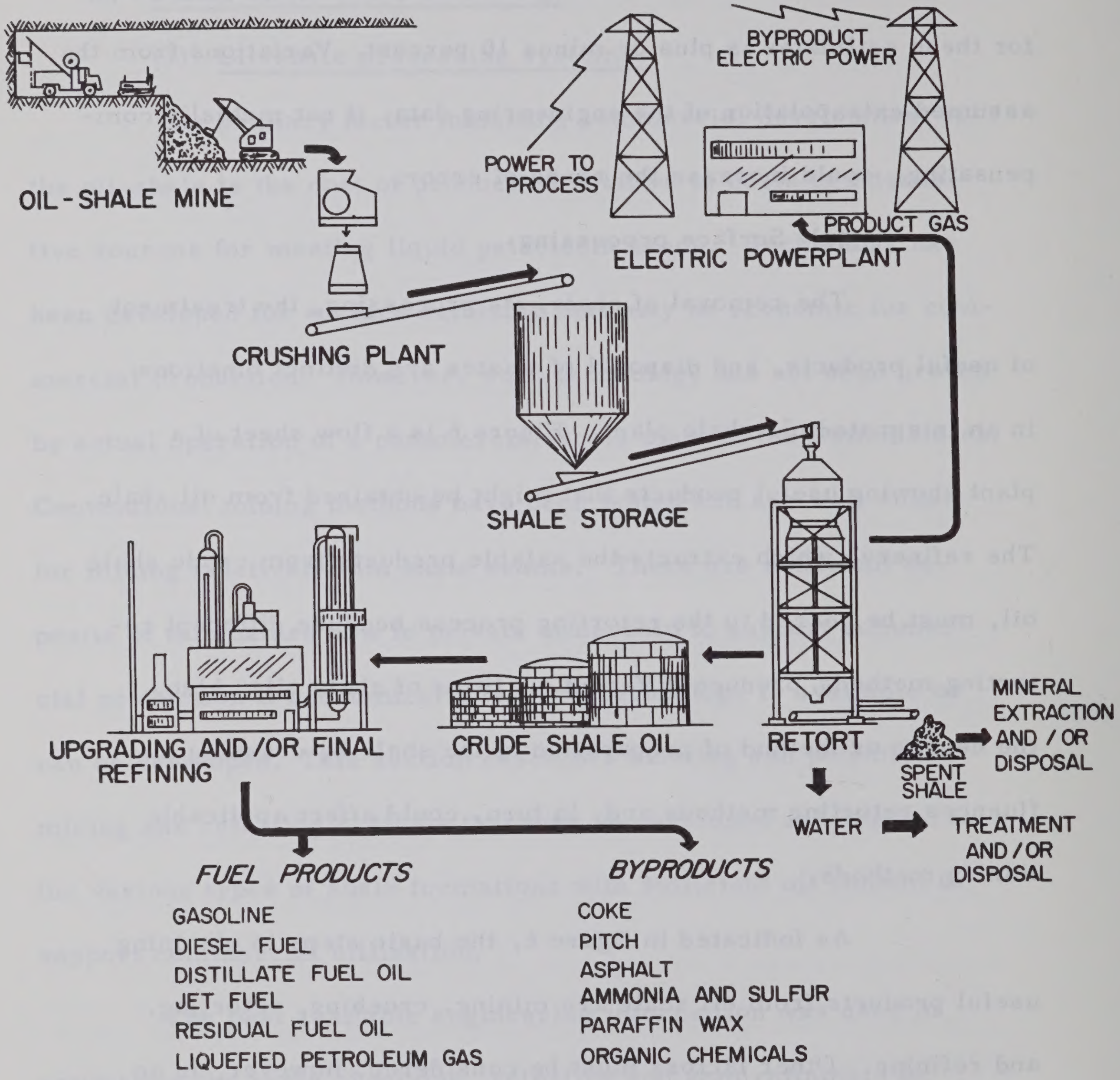
Even where technology is well established, cost estimates have an inherent range of error due to numerous judgments which must be included in the estimates. A reasonable margin of error for these estimates is plus or minus 10 percent. Variations from the assumed extrapolation of the engineering data, if not mutually compensating, could increase the range of error.

(a) Surface processing

The removal of shale, its processing, the treatment of useful products, and disposal of wastes are distinct functions in an integrated oil-shale plant. Figure 6 is a flow sheet of a plant showing useful products that might be obtained from oil shale. The refinery, which extracts the salable products from crude shale oil, must be geared to the retorting process because different retorting methods produce different qualities of shale oil. Also, the degree or method of preparation of the shale by crushing influences retorting methods and, in turn, could affect applicable mining methods.

As indicated in figure 6, the basic steps in obtaining useful products from oil shale are mining, crushing, retorting, and refining. Other factors must be considered, however, in an overall system. Huge quantities of spent shale will be produced, in the form of either solid lumps or a fine powder, depending on

FIG. 6. - OIL-SHALE SURFACE PROCESSING SYSTEM



the retorting method. Also, if the shale is processed to recover minerals, it may be wet or dry. As a result, methods for disposing of waste material will vary. If the material is to be returned to the mine, mine-development plans will have to provide for such return. In addition, each of the retorting systems produces different quantities and qualities of water and gases.

(b) In situ processing

Mining, crushing, and conveying shale to a retort and disposing of spent shale constitute a substantial part of production costs. Consequently, interest has developed in underground, or in situ, retorting as a means of eliminating that material handling and its costs. In addition to possible cost reductions, in situ processing would offer other advantages over surface retorting. It might be more adaptable for exploiting beds too thick, too badly faulted, or too deep to be readily amenable to conventional mining methods. It could eliminate the inherent problems in storing spent shale for subsequent disposal thus making workable a larger part of an oil-shale lease. Controls to prevent air pollution, which would be required with aboveground processing, could be eliminated or reduced. Additionally, the problem of possible contamination of surface or subsurface waters by surface disposal of spent shale wastes would be minimized.

As now envisioned, however, in situ processing would have at least one important disadvantage. It is not adaptable to concurrent recovery of associated minerals unless some type of in situ leaching technology is developed. They could be recovered, however, by later conventional mining.

Methods are yet to be developed for creating permeability in shale deposits so as to allow injection of retorting fluids and recovery of shale oil by in situ processing. Approaches now being tested include hydraulic pressure, high voltage electricity and liquid chemical explosives. If the major problem of attaining adequate permeability during the retorting process can be overcome, other problems will remain: (1) combustion may be difficult to control, which could result in a low percentage recovery of the shale oil and (2) pressures at which air or oxygen must be supplied to support combustion are unknown.

Nonnuclear in situ technology may be applicable to both thick, deep seams and to thinner oil-shale deposits under shallow cover to the extent that flow of retorting gases to the recovery wells can be controlled.

The use of a nuclear explosion to fracture large quantities of shale for subsequent processing in place is another concept that is being considered. This technique, applicable primarily to relatively thick deposits under substantial overburden, might permit the fracturing of several million tons of shale at one time. Such deposits occur over a large area of the Piceance Creek Basin in lands that are Federally owned. A conceptual arrangement for a commercial-scale, in situ operation using a nuclear explosive is shown in figure 7.

(c) State of knowledge

The relative states of knowledge of the various operations required in oil-shale processing by either conventional or in situ techniques are compared in figure 8. The technology, of course, is more highly developed for conventional surface processing. Experience with some of the steps of in situ processing has been gained through petroleum operations, but these have not been demonstrated to be applicable to oil shale.

(2) Technology selected for cost estimates

(a) Surface retorting

Three retorting systems have been developed to the point of possible commercial application. Data in sufficient detail were not available to the Department of the Interior to evaluate the costs of the two non-Government processes (Oil Shale Corporation and Union Oil) in the same manner as for the gas-combustion retort. In terms of mechanical complexity, however, the gas combustion process, developed by the Bureau of Mines, is the

FIG. 7. - CONCEPT OF A COMMERCIAL-SCALE NUCLEAR IN SITU RETORTING PLANT

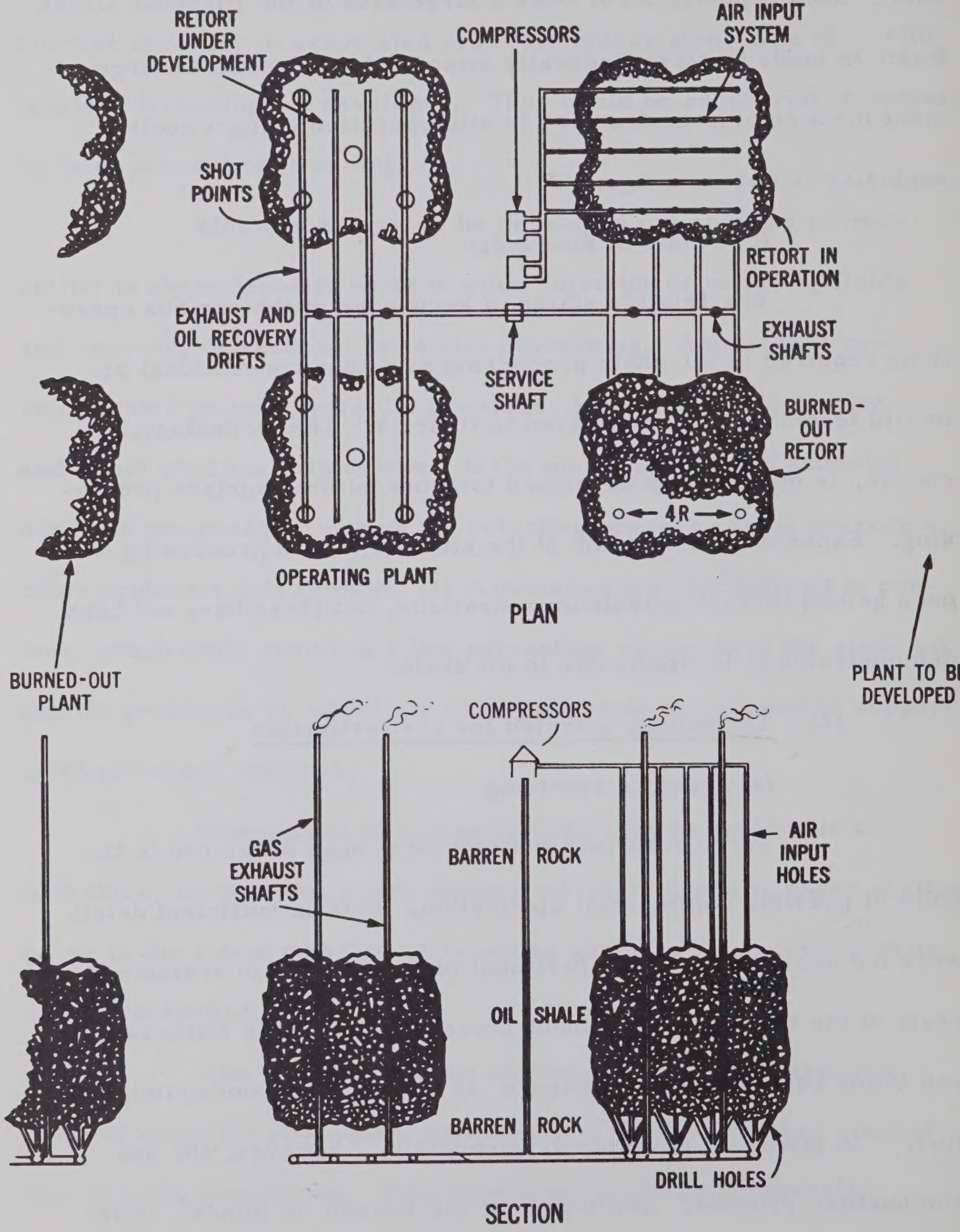
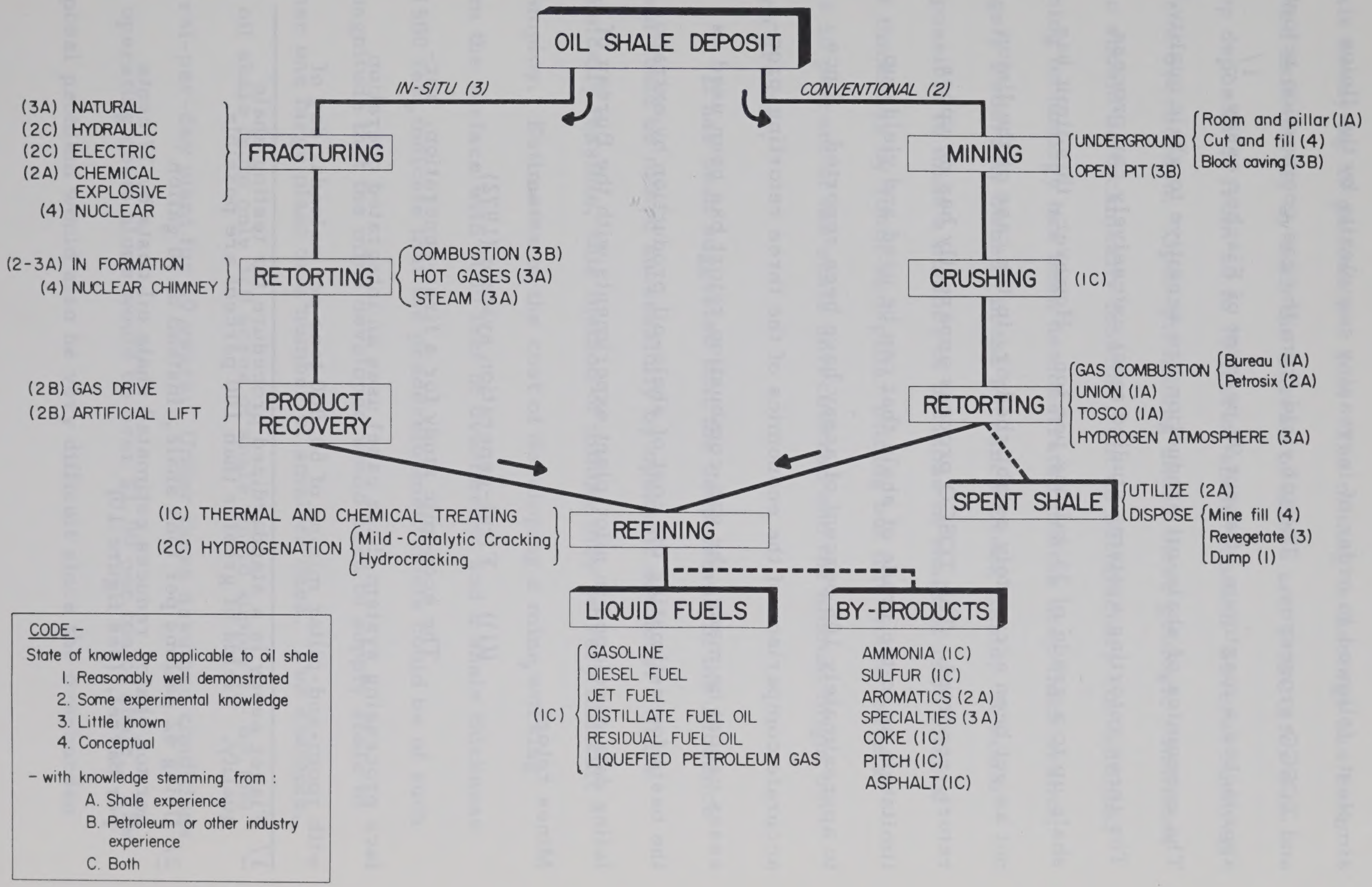


FIG. 8.- OIL-SHALE UTILIZATION—ROUTES AND STATE OF KNOWLEDGE



simplest, followed in order of increasing complexity by the Union and TOSCO processes. The oil yield from the gas combustion retort approaches a maximum of about 95 percent of Fischer assay. [1] The economics of shale-oil production are sensitive to shale quality. [2] The three retorting systems studied most extensively can process shale up to a grade of 35 gallons per ton. However, this limit has not as yet been accurately established or, in the case of the Union retort, reported. The TOSCO process apparently has no upper limitation as to the grade of shale that can be used and yields up to approximately 105 percent of assay have been reported. Since accurate comparison of the economics of the three retorting processes cannot be made, the gas-combustion retort has been used as the basis for estimating the cost of shale-oil production by extrapolating data developed in pilot-plant experiments with the Bureau of Mines retort.

((1)) First-generation system (1972)

The economic study for a first-generation, surface processing system (base case) uses an integrated operation with room-and-pillar mining of 60,000 tons per calendar day of

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1/ Fisher assay is a standardized procedure for testing shale quality. Yields of greater than 100 percent are possible.

2/ Using 42 gallons per tons shale, instead of 30 gallon per ton shale, reduces estimated shale oil costs by 77 cents per barrel. (see figure 10) shale assaying 30 gallons per ton. The mining technology has been tested extensively by both the Bureau of Mines and TOSCO for outcrop deposits of from 50 to 70 feet of shale beneath several hundred feet of overburden. Open-pit mining under these geologic conditions also should be technically feasible, but no satisfactory conventional mining technology has been demonstrated for the deep thick seams, largely Federally owned, in the Piceance Creek Basin. It would be possible to mine a number of horizons in shale of 1500 to 2000 feet thickness by room-and-pillar mining but this would leave at best 50 percent of the shale unrecovered and the amount might be much greater.

It has been suggested that the deep seams in the Piceance Basin could be mined successfully by open-pit methods. While technically feasible, this method of mining may be very difficult to employ. Estimates of the cost of developing a mine, working from the surface with 1000 feet of overburden and a shale thickness of 1500 feet, indicate that the predevelopment costs could be of such a magnitude that the mine developed would need to supply shale to either one large plant or a number of smaller ones. For example, the oil shale from only 320 acres of shale would supply 1 - 60,000 barrel-per-day plant for 20 years. Under these assumed conditions the operating costs alone would be over $1.00 per ton of shale. The disposal problem would also be very difficult since the overburden from such a mine would cover 13,000 acres to a depth of 100 feet even if there were no expansion of the overburden after removal from the ground. [1]

In the assumed first generation surface processing system, mined shale undergoes primary crushing at the mine site and then is transported to the retorting area where it is crushed further and screened to produce a minus 3-inch product. Seven gas-combustion retorts are estimated to produce a total of 40,000 barrels of crude shale oil per calendar day. Surface disposal of the waste material is estimated at about 20 million cubic yards per year. As a feasible alternative to surface disposal part of the spent shale could be returned to the mine presuming the mining development plan provided for such disposal.

The crude shale oil is partly refined by delayed coking, followed by hydrocracking of the coker distillate to obtain a product low in sulfur and nitrogen and containing 60 volume-percent of material in the gasoline boiling range and 40 volume-percent in the diesel-fuel range. The product is a hydrocracked distillate of 35,000 barrels per calendar day with byproducts of 1,050 tons of coke, 90 tons of ammonia, 45 tons of sulfur, and 3 million standard cubic feet of gas. Since technology has not yet been demonstrated for possible economic recovery of associated minerals, their yield and value cannot be appraised.

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[1] A new mining technology suitable for these deposits is described later in this section.

The design of the retorting system is based on two major assumptions. First it is assumed that cylindrical units, 45 feet in diameter, are operable. (The largest gas-combustion retort that has been operated by the Bureau of Mines is a rectangular unit measuring 6 feet by 10 feet.) The second assumption is a shale throughput rate of 500 pounds per hour per square foot of cross-sectional area. (This is approximately double the rate that has been demonstrated by the Bureau.) Allowing approximately 2 to 3 years for engineering design and experimental operation of a prototype unit with concurrent development of a mine, it is reasonable that a plant of this magnitude could be put into operation in 1972, with a total production cost (after byproduct credit,[1] but exclusive of resource costs[2]) in the range of $2.68 to $3.28 per barrel of semirefined crude oil.[3] The method used for making the DCF calculations are shown in Appendix B.

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[1] Assumption made that all byproducts can be marketed.

[2] The term "resource cost",as used throughout this report, is used for charges for the shale in place.

[3] All costs are for an assumed 12 percent discounted cash flow (DCF), 30 gallon-per-ton shale and with a 15 percent depletion on the oil shale. DCF is the method of calculating the rate of return on net invested capital and is used widely by financial analysts.

((2)) Improved first-generation system (1976)

The approximate distribution of capital and operatining costs for the first-generation processing system are shown in table 3. Of the 3 major cost areas -- mining, retorting, and refining -- it is believed that petroleum refining technology, which with changes can be adopted to refining shale oil, is approaching a plateau, and only evolutionary improvements are visualized in the near future unless unique new systems are developed for shale oil. Improvements in mining (open-pit and room-and-pillar) are expected and probably will require system changes. As these would be extensions of known technology, they should be attainable with adequate research effort. The mining methods to be studied, however, would not be suitable for the thick, deep seams of the Piceance Creek Basin without either very low recovery of the oil shale and/or increased mining costs. By 1976, a 60 foot diameter retort probably could be developed after obtaining experience with the 45-foot, first generation retort. If so, final production costs of an improved first generation system (after byproduct credit, but exclusive of resource costs) could be in the range of $1.91 to $2.33 per barrel of semi-refined crude oil.

Table 3 - Approximate distribution of capital and operating costs, first-generation processing system

	Capital investment[1]		Operating costs	
	Percent	MM$	Percent	MM$
Mining (room-and-pillar)	15	20.7	46	12.3
Crushing and conveying	3	4.1	2	0.5
Retorting	31	42.8	20	5.4
Partial refining (upgrading)	49	67.6	31	8.3
Waste disposal[2]	2	2.8	1	0.3
Total	100	138.0	100	26.8

[1] Does not include ~~working capital or~~ cost of shale.

[2] Cost could be somewhat higher if spent shale leaching or other environmental factors should require additional controls.

((3)) Second-generation system (1980)

It is likely that future technologic advances in mining and retorting could be incorporated into a "second generation" oil-shale plant.

An advanced retorting system, that could improve the overall economics of producing shale oil, would involve: (1) utilization of the fuel value of the carbon deposited on spent shale; and (2) elimination of the present internal-combustion feature in favor of a system using gas as a heat carrier to retort the raw shale. The gas would be heated through external indirect heat exchange, using heat developed by burning the carbon in the spent shale. This method offers increased efficiency and the potential for increasing the oil yield to approximately the assay value of the shale. In addition, the gas product would have greater value since it would not be diluted with combustion products and air.

A large research and development effort would be required for adequate evaluation of the envisaged "second-generation" retorting system, and it probably could not be put into large-scale operation before 1980.

A new mining method, "cut-and-fill," might be developed. It would eliminate the cyclic operation of drilling and blasting typical of the room-and-pillar method and might be suitable to the type of deposits found in the Piceance Basin. In addition, it should recover over 90 percent of the oil shale by utilizing shale wasted under other systems to maintain a working floor, provide support for the stope[1/] walls and roof, contribute to effective waste disposal and mitigate other environmental problems. The key elements of such a system are continuous shale breaking, loading and haulage, and positive ground control by filling the underground voids with spent shale. Information to date indicates that the physical properties, thickness, and structure of the thick shale

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[1/] A mining term used for an excavation from which ore has been extracted, usually in steps.

formations are favorable to the introduction of large, high capacity machines which would substitute for the less efficient drilling, blasting, and loading cycles inherent in most underground mining methods and permit automation to a high degree.

A shaft first would be sunk to the bottom of the shale formation as a starting point for the mechanical miner. After the machine completes its pass of the full length of the stope,[1/] it then would make a second adjacent pass while the void made by the first pass is filled with spent shale. This procedure would be repeated until the full stope width and height is mined. After a stope is completed, the mechanical miner could be lowered down a stope extending from the top to the bottom of the oil-shale deposit where it could begin mining the next stope using the spent shale as the floor from which to operate the machine.

By 1972, research and development could establish the feasibility and provide basic design criteria for a "cut-and-fill" mining system. After 1972, it could be tested in pilot operations. It is estimated that this mining method could reduce the current cost of comparable room-and-pillar mining by 25 percent and permit mining the very thick beds with more complete utilization of the resource. This mining method combined with the second-generation retorting system would result in final production costs (after byproduct credit, but exclusive of resource costs) in the range of $1.42 to $1.74 per barrel for semirefined crude oils.

(b) In situ retorting

((1)) Nuclear fracturing followed by underground retorting

The basic assumptions of producing shale oil using a nuclear explosion to prepare the shale for retorting were developed by the Atomic Energy Commission, the Bureau of Mines, CER Geonuclear Corporation, and Lawrence Radiation Laboratory.[1] Adjustments were made in these assumptions (table 4) so that the in-situ shale-oil production from the chimneys and fractured zone between them would equal the expected production over a 20-year period from a surface plant. Figure 9 shows the arrangement, to scale, of the nuclear chimneys that would be retorted if the chimneys were placed 1,000 feet apart (edge to edge) to permit maximum fracturing of the zone between chimneys.

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[1] Project Bronco: A Joint Government Industry Study of Nuclear Fracturing & In Situ Retorting of Oil Shale, PNE-1400, October 1967, 64 p. Available from Clearinghouse for Federal Scientific and Technical Information, National Bureau of Standards, U. S. Department of Commerce, Springfield, Virginia 22151. Printed copy $3.00; Microfilm $0.65.

FIG. 9. - ARRAY OF NUCLEAR EXPLOSION FOR MAXIMUM FRACTURING EFFECT

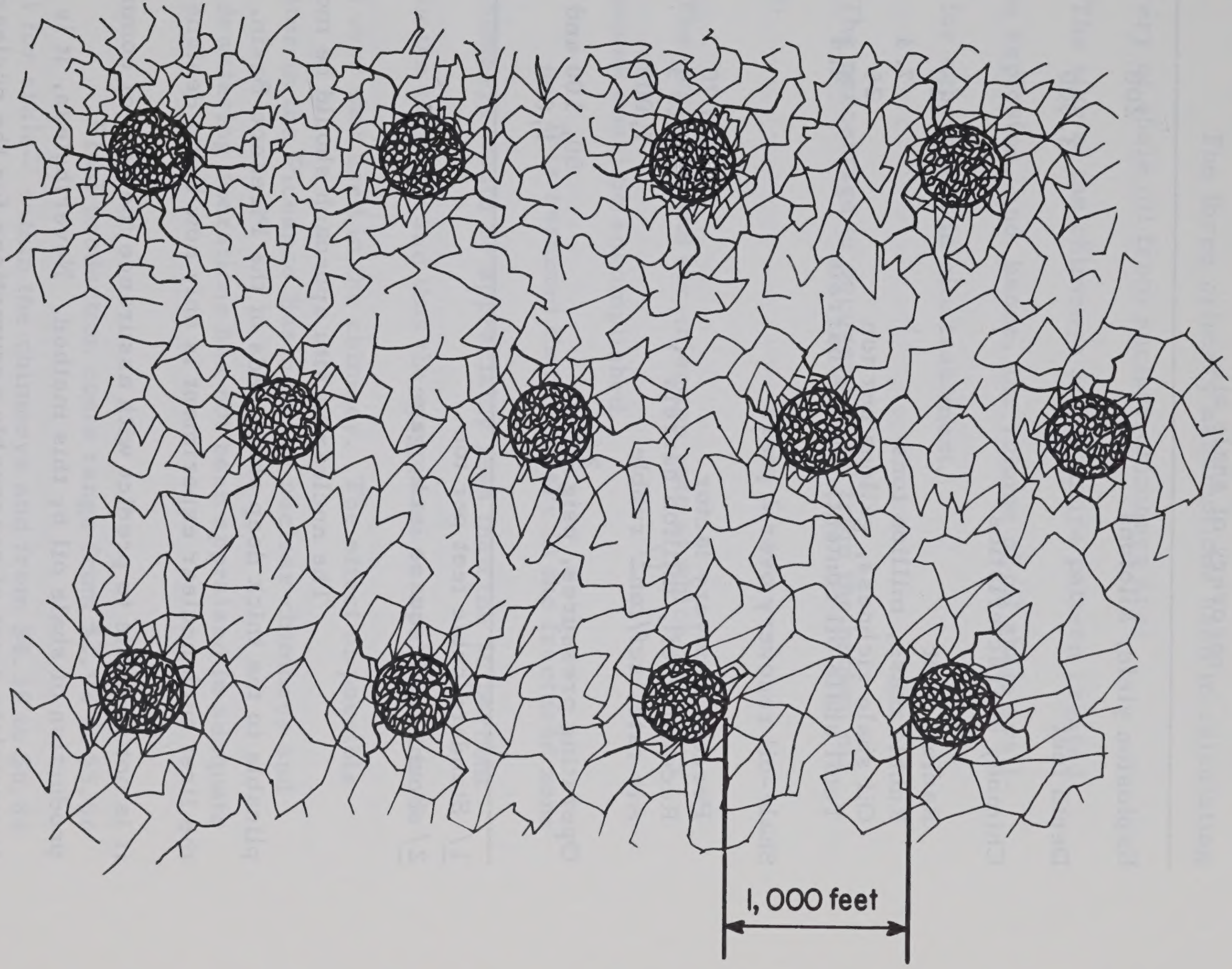

Table 4 - Basic assumptions, nuclear fracturing, in situ recovery of shale oil

Explosion yield, kilotons	200
Depth feet	3,000
Chimney characteristics	
Radius, feet	210
Rubble mass, million tons	7.3
Oil shale richness, gallons per ton	25
Total shale oil content, million barrels	4.4
Shale-oil recovery over 2 years	
Percent recovery factor	50 and 70
Recovered oil, million barrels	2.2 to 3
Air rate, scf/ton1/ rubble	7,000
Operating pressures, psig 2/	50, 100 and 1,000

1/ Standard cubic feet per ton

2/ Pounds per square inch, gage

The nuclear in situ approach should be most applicable to the thick deep shale beds of the Piceance Basin. Since the first such nuclear experiment is only now being designed, however, it is not possible to predict with assurance the cost of commercial production of shale oil by this method. Nevertheless, it is possible to postulate a set of reasonable assumptions for the nuclear chimneys and to calculate the costs of shale oil produced.

The three primary assumptions used in calculating the recovery of shale oil from nuclear chimneys are:

1. The size of the chimneys and fracture pattern created by the explosion, and hence, the volume of oil shale available for subsequent in situ treatment.
2. The percentage of recovery of oil from the broken oil shale.
3. The pressure and air-injection rate at which recovery operations could be accomplished.

It is assumed that recovery in the fractured zone between chimneys would be appreciably less than the 70 percent expected in the chimney and that the air pressure would need to be increased over that used in the chimney. The effect of possible ground water in the Piceance Basin on the nuclear chimneys and attendant dewatering operations has not been appraised in adequate terms.

Final production costs range from $2.98 to $3.56 per barrel for shale[1] within the chimneys and from $4.38 to $6.84 (after byproduct credit but exclusive of resource cost) for the combined retorting of chimneys and the fractured zones between them.

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[1] With an average grade of 25 gallons per ton.

Those estimates reflect an assumption that very high air pressure will not be required to prevent ground water from flowing into the retort areas.

((2)) Non-nuclear fracturing followed by underground retorting

A processing system has been postulated so that order-of-magnitude costs could be developed for non-nuclear fracturing followed by in situ recovery. This method might be applicable both to deposits near the outcrop and to the thick deep deposits of Piceance Creek Basin. It must be emphasized, however, that the cost estimates are based on what are now considered to be the best engineering assumptions that can be made at this time.

The first conceptual design for a commercial-size operation is postulated on the same geologic conditions as in nuclear in situ so that the two methods may be compared. Initial development would require drilling and casing two mile-long rows of wells. The rows would be 100 feet apart, and each row would contain 102 wells extending through a shale zone 1500 feet deep. The retorting would be done by perforating the first 100 feet of casing in the shale zone every 10 feet and hydraulically fracturing the deposit from each of the injection wells situated in one row through the formation to the producing wells in the second row 100 feet away. The process would be repeated for successive 100 foot depths until the entire 1,500-foot shale zone had been retorted for the horizontal distance of 100 feet. A second design of non-nuclear in situ assumes conditions similar to those near the outcrops. Costs (after byproduct credit, but exclusive of resource costs) range from \$3.74 to \$4.62 per barrel for non-nuclear in situ in the deep thick seams to \$4.41 to \$5.32 per barrel in the thinner seams with shallower overburden. The higher costs for the shallow shale beds result from the higher ratio of overburden to shale thickness.[1]

(2) Costs of shale oil

(a) General considerations

((1)) Land

In the cost calculations for this study, no value was assigned to the resource since the objective was to determine what the in-place value of oil shale would be for various assumptions with regard to the state of mining, retorting, and refining technology. To obtain resource value from these calculations it is only necessary to estimate the market price of the shale oil at the plant. Sales of lands in large units have been infrequent in recent years but it appears that the capital investment of \$5 to \$10 million would be required to purchase sufficient oil-shale properties at present market prices to supply the needs of a first-generation plant. Since the higher figure is less than 7 percent of the total capital investment, land cost is not a major factor under present conditions. That figure represents an in-place value of roughly 1 to 2 cents per barrel of shale oil--a value that can be expected to be much greater when a satisfactory and economic technology has been developed to exploit the resource.

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[1] Overburden 500 feet; thickness of shale 60 feet with an average quality of 30 gallons per ton.

((2)) Water

The cost used in the economic studies for raw water in the Upper Colorado River Basin was based on a recent contract between the Government and The Oil Shale Corporation for storage water. This cost ($0.027 per 1,000 gallons) is equivalent to less than 1/2 cent per barrel of shale oil which represents an insignificant factor in the total operating cost. As the industry is developed, water costs may increase, but they would have to increase at least tenfold to affect these estimates materially. As will be shown in the next chapter, there is sufficient water to support an industry of 1 million barrels per day in Colorado and a larger industry in Utah and Wyoming.

((3)) Pollution

Estimates of water pollution abatement costs are based on the treatment believed necessary to assure that the quality of retorting and refinery waste water discharged into surface streams would meet Federal and State water quality standards. The temperature of the discharged water would be 20°F higher than that of the surface water. Because the volume of water would be small relative to the size of the river receiving it, the effect of this temperature difference on other water uses should be insignificant for a 35,000 barrel-per-day semirefined shale-oil plant. However, if thermal pollution becomes a problem as the industry develops, additional control requirements could result in increased production costs.

The special problems associated with waste water formed during retorting and with leaching from surface disposal of spent shale have not been included in the cost estimates. Most, if not all, of the water formed during retorting, however, may be used to control dust that would result from disposal of the waste material. If it cannot be used for this purpose, other treatment measures may be required which also could result in increased production costs.

Except for dust control, air-pollution problems need not be considered for the first-generation oil-shale installation since the sulfur in the shale, appearing in a gas stream as H_2S during the semirefining of the crude shale oil, is recovered as elemental sulfur using existing processes. The other potential pollutant, nitrogen oxides, is recovered as a byproduct in the form of ammonia. In advanced retorting technology, control of sulfur dioxide from the combustion of spent shale may be required.

((4)) Solid-waste disposal

The cost of moving spent shale to a surface disposal area by conveyor, with provisions for compacting the material, has been included in the estimates of capital investment and annual operating costs. These costs amount to about 2 percent of the total. Waste disposal, therefore, is a relatively insignificant cost item. If the waste is returned to the mine the cost would be higher depending on the mining method and the location of the mine with respect to the retorting plant.

(b) Capital and operating costs

((1)) Surface processing

The estimated capital and operating costs for several processing alternatives for the years 1972, 1976, and 1980, are shown in table 5.

To test the effect of throughput,an estimate was also made of the cost if the plant could be operated at a level 10 percent above the capacity for which the engineering estimates were made. The increased throughput would reduce the operating cost about 10 cents per barrel.

The effect on operating costs as a function of the quality of the shale also was estimated. If the 30-gallon-per-ton

Table 5. - Operating cost of oil-shale processing alternatives 1/

MINING OPTIONS	RETORTING OPTIONS				
	First generation, 1972		Improved first generation, 1976		Second generation, 1980
	7, 45-ft-diam units	Operation 10% above design	7, 60-ft-diam units	28, 60-ft-diam units	7, 60-ft-diam units
Room and pillar					
Capital investment, million dollars	$138	$142	$197	$724	$204
Annual operating cost, million dollars	26.8	28.1	35.7	134	36.3
Cost per barrel: 2/					
Before by-product credit, dollars	2.10	1.99	1.57	1.48	1.52
After by-product credit, dollars	1.49	1.39	0.97	0.87	0.55
Improved room and pillar					
Capital investment, million dollars	142	146	203	748	210
Annual operating cost, million dollars	25.4	26.5	33.2	124	33.8
Cost per barrel: 2/					
Before by-product credit, dollars	1.99	1.88	1.46	1.36	1.41
After by-product credit, dollars	1.38	1.28	0.85	0.76	0.44
Open pit					
Capital investment, million dollars	138	141	196	721	204
Annual operating cost, million dollars	26.6	27.8	35.3	133	35.9
Cost per barrel: 2/					
Before by-product credit, dollars	2.08	1.98	1.56	1.46	1.50
After by-product credit, dollars	1.47	1.37	0.95	0.85	0.53
Improved open pit					
Capital investment, million dollars	139	143	199	730	206
Annual operating cost, million dollars	24.2	25.1	31.1	115	31.6
Cost per barrel: 2/					
Before by-product credit, dollars	1.89	1.79	1.37	1.27	1.32
After by-product credit, dollars	1.28	1.18	0.76	0.66	0.35
Advanced cut and fill					
Capital investment, million dollars	148	152	214	791	221
Annual operating cost, million dollars	23.7	24.7	30.3	112	30.9
Cost per barrel: 2/					
Before by-product credit, dollars	1.86	1.75	1.33	1.24	1.29
After by-product credit, dollars	1.25	1.15	0.72	0.63	0.32

1/ Capital investment includes working capital and operating cost includes depreciation, but no allowance is made for Federal income tax, cost of capital, or return on investment.

2/ Cost per barrel is in terms of semi-refined shale oil and 1967 dollars.

shale were replaced by a 42-gallon-per-ton shale and the gas-combustion retort could be used successfully on this richer shale, the cost per barrel of semirefined shale oil could be reduced by 77 cents.

In the 1976 technology, the effect on operating costs of increasing plant size was determined. In increasing the plant size from 62,000 barrels per day to 250,000 barrels per day, the saving in operating costs was 9 cents per barrel. Very difficult materials handling problems might be encountered, however, in moving the required volumes of shale into a central plant and in removing spent shale.

Figure 10 compares the economics for the various aboveground retorting systems using a discounted cash flow of 12 percent.

((2)) In situ processing

Since less is known about the technology of an in situ processing, the capital and operating costs were determined for a number of assumed values for major process variables. The operation was scaled to produce 35,000 barrels per day of semirefined crude shale oil for 20 years. The estimates are shown graphically in figure 11 for a variety of conditions for an in situ operation using nuclear explosives for fracturing the shale. The 1,000 psi air

FIG. 10.- COST OF SHALE OIL AT ZERO RESOURCE VALUE
USING ABOVEGROUND GAS COMBUSTION RETORTING

(12 PERCENT DISCOUNTED CASH FLOW)
30-GALLON SHALE (unless noted)

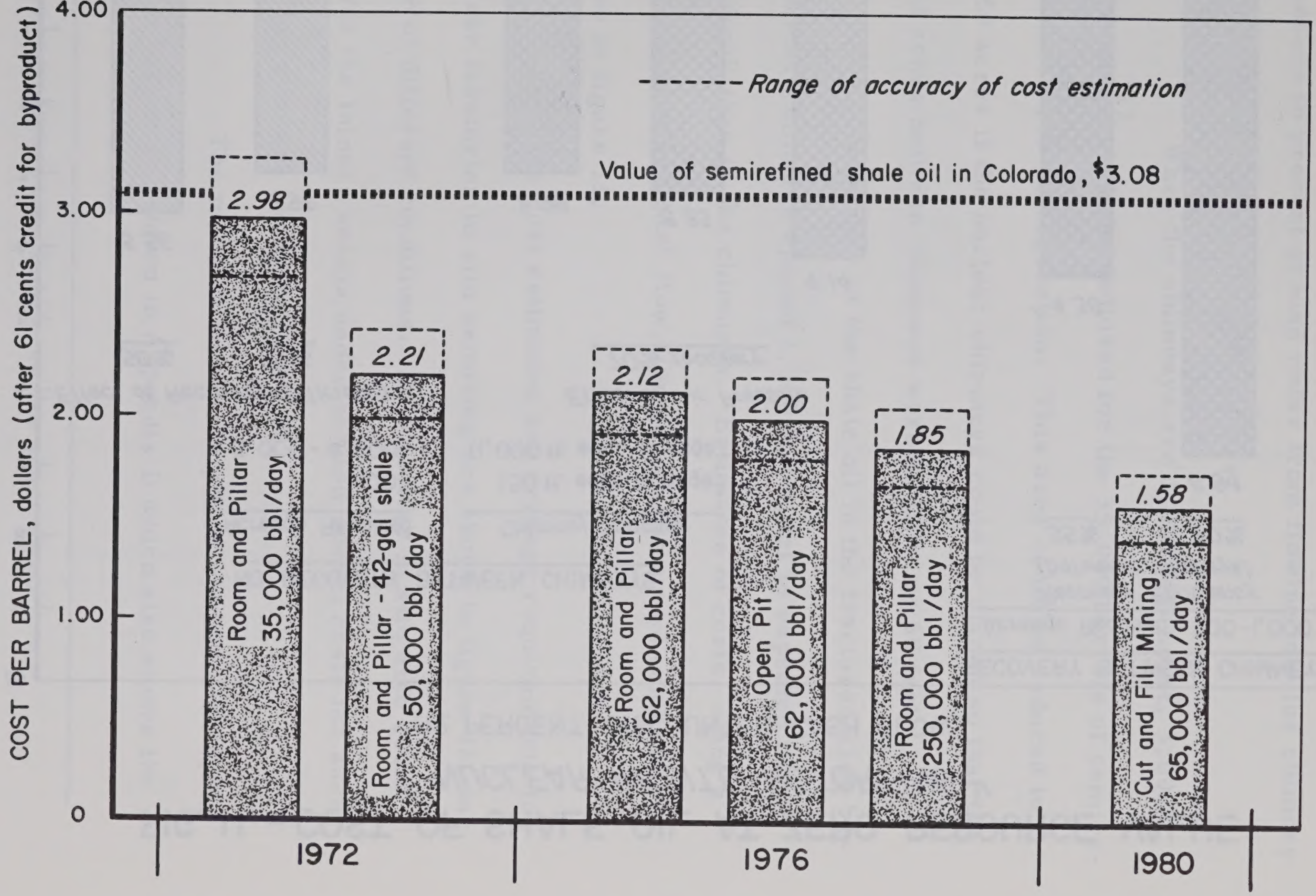
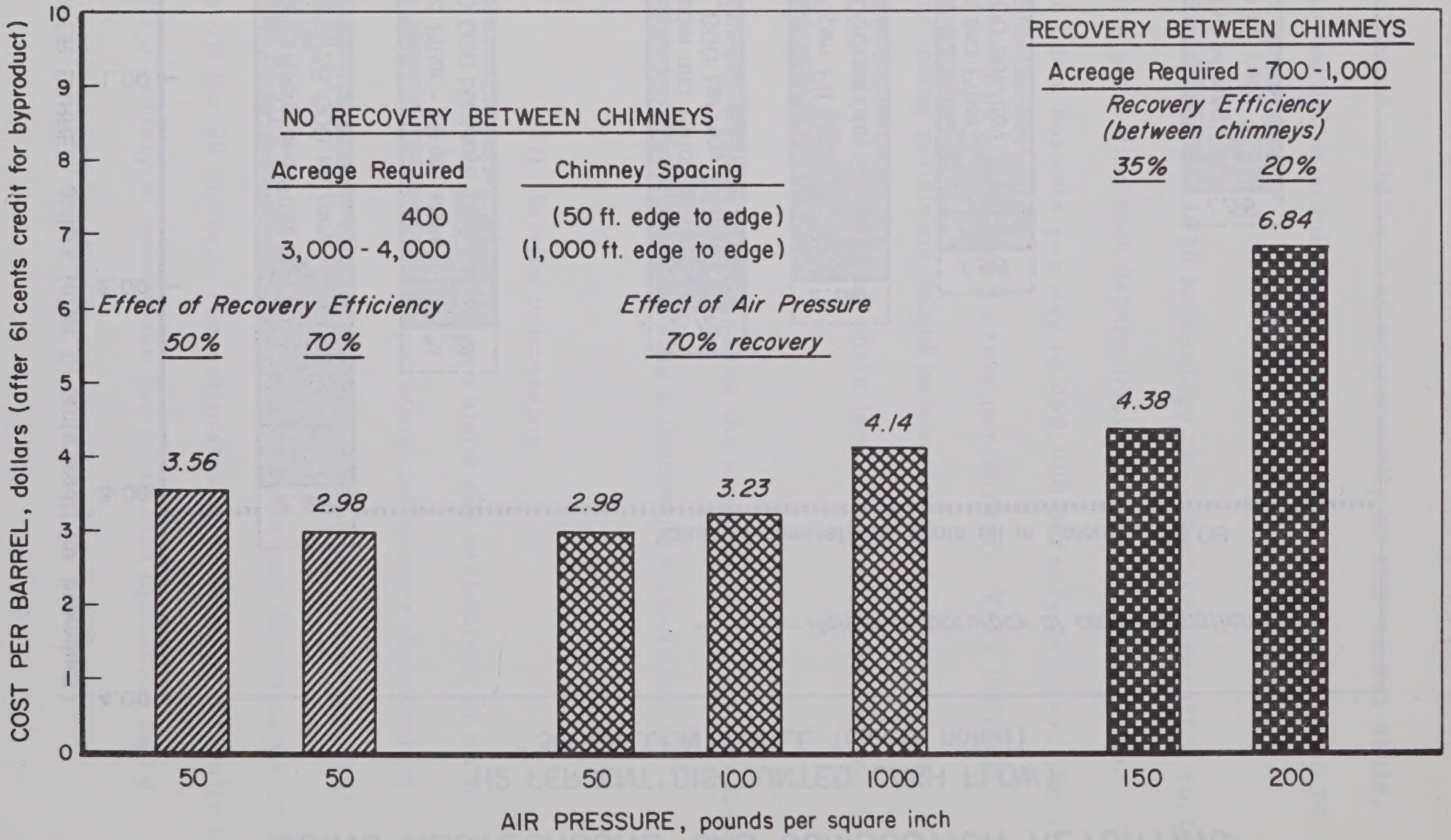


FIG. 11. - COST OF SHALE OIL AT ZERO RESOURCE VALUE

NUCLEAR IN SITU RETORTING [1]

(12 PERCENT DISCOUNTED CASH FLOW)



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[1] 1,000 feet of overburden, 1,500 feet of oil shale
Average shale quality, 25 gallons per ton

pressure case was estimated since it may be necessary to use this high pressure to prevent ground water from flowing into the chimney and interfering with the retorting process.

When the chimneys are 1,000 feet apart, 3,000 to 4,000 acres[1] would be required for the 35,000 barrels of semirefined shale oil per day operation. This area could be reduced to 400 to 550 acres if the nuclear chimneys could be placed so that the fractured zones between chimneys were as little as 50 feet.

Recovery of the shale oil in the fractured area between nuclear chimneys spaced 1,000 feet apart is expected to be more difficult than in the chimneys. Estimates of costs, using a 12 percent discounted cash flow, for several assumed conditions are shown in figure 11.

The cost estimates and acreage requirements for non-nuclear fracturing in situ retorting are shown in figure 12, for a number of different conditions. Non-nuclear in situ also could be used for the thinner seams under shallow cover; costs for such an operation also are shown in figure 12.

The methods and assumptions used in developing these calculations are shown in Appendix B which also shows the

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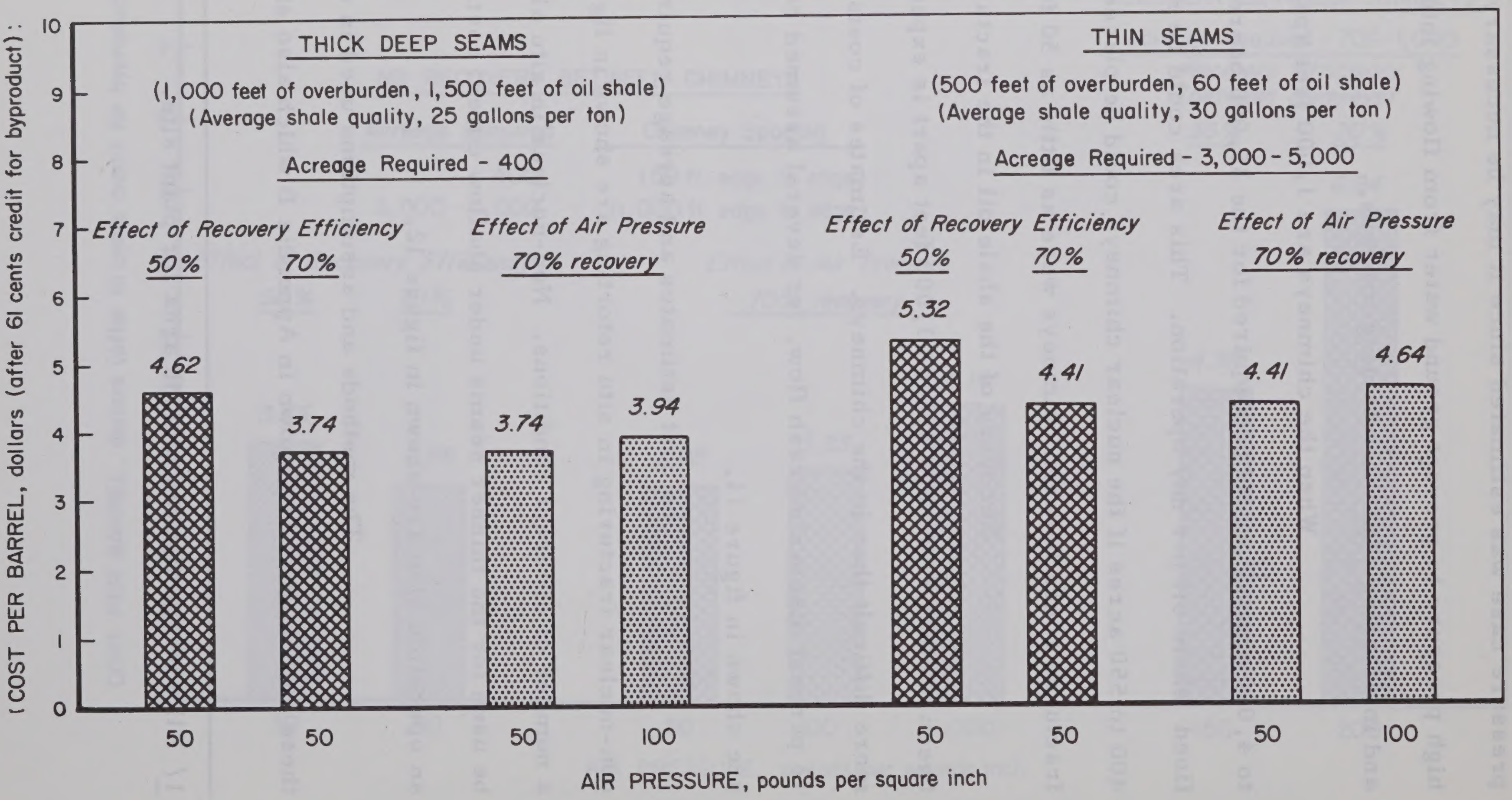
1/ All average figures include area for plant site.

FIG. 12. - COST OF SHALE OIL AT ZERO RESOURCE VALUE

NON-NUCLEAR IN SITU RETORTING

(12 PERCENT DISCOUNTED CASH FLOW)



present value of the resource for the different plant types and mining systems.

(3) Associated minerals

To determine whether byproduct credits could be expected from the associated minerals, projections were made of demands for alumina and sodium compounds and the anticipated costs of recovery.

The need for alumina is growing rapidly. The United States consumed 6.0 million tons in 1966 and by 1980 is expected to consume 20 million tons. Annual consumption of soda ash is expected to total 11 million tons by 1980, compared with a 1966 consumption of 6.8 million tons.

The quantities of alumina and soda ash that could be recovered from spent shale depend on the initial concentrations of dawsonite (the alumina mineral) and nahcolite (the soda ash mineral) in the raw oil shale, as well as on the efficiency of the recovery processes. The average concentrations from the saline-rich dawsonite-bearing zone reported from a core hole drilled near the center of the Piceance Creek Basin[1/] was used to estimate the potential recovery of alumina and soda ash.

[1/] Based upon average dawsonite concentration of 11 weight-percent and nahcolite of 15 weight-percent. Hite, Robert J and Dyni, John R. Potential Resources of Dawsonite and Nahcolite in the Piceance Creek Basin, Northwest Colorado, Colorado School of Mines Quarterly, v. 62, No. 3, July 1967, pp. 25-38.

With these average concentrations, and assuming that all of the spent shale was processed at a shale-oil production rate of 35,000 barrels per day of semirefined oil (0.3 percent of total liquid-fuel demand in 1980), one plant could yield enough spent shale to produce about 3 percent of the anticipated 1980 requirement for alumina. A single plant with the same shale-oil production rate could provide about 15 percent of the projected 1980 needs for soda ash. Recovery of soda ash alone from the spent shale does not appear to be economical at even the highest concentrations present in the shales that have been evaluated.

An order-of-magnitude operating (plant-manufacturing) cost for treating spent shale (with shale at zero cost) was estimated to be $80 per ton of extracted alumina. Even with a credit of $15 to $20 per ton of extracted soda ash, the process would not now compete with the Bayer process, which has an operating cost of $45 to $50 per ton of alumina when using the same cost estimating methods. In addition, byproduct credits for soda ash could only be assumed for a single plant since the market for soda ash would be saturated quickly. Recovery of these minerals from spent shale may become economically attractive, however, as a result of future technologic developments in extraction processes. Such reductions may be expected since only limited research has been conducted on process development.

Even if the research is successful, the mineral-extraction industry would have to compete for water with oil-shale processing. When the size of the shale-oil industry approaches 1 million barrels per day in Colorado, the size of the mineral extraction industry may be limited by the availability of water since the water consumption for recovering minerals from a given sized shale-oil plant are several times higher than the maximum expected for all other processing operations (including oil shale) and for urban requirements.

B. Economic outlook for early oil-shale development

The achievement of economic shale-oil production could have far-reaching public benefits in assuring an adequate and secure supply of liquid petroleum for the Nation and the Free World consistent with utilizing this vast resource in the best public interest.

The timing and rate of development of an emerging oil-shale industry also would be influenced by non-technologic factors such as increase in the U. S. market for oil, government policies on oil imports, prorationing, tax treatment and leasing conditions for oil shale. An increase in oil imports, for example, might tend to delay the start of an oil-shale industry, while a decrease in those quotas might accelerate it. Changes in the Federal tax treatment of either crude oil or shale oil also could have an appreciable impact.

The number and sizes of Federal leases offered, refusal prices, size of royalties required, conservation, performance and environmental requirements, and patent provisions all could affect the potential number of entrants into a shale-oil industry and the pace of development.

Another policy uncertainty that may affect the pace of shale-oil development is possible changes in State prorationing. Since only three States, whose current petroleum production is less than 7 percent of the U. S. total, have oil-shale deposits that might be economic initially, other oil-producing States subjected to prorationing may take further steps to keep their oil production competitive.

The rates at which Outer Continental Shelf leases are offered and production increases, and the degree of success in other domestic drilling programs could affect the rate at which a shale-oil industry emerges. Disturbances throughout the world or changes in government policy could result in greater incentive for oil company investments in the United States and sharply accelerate the pace of shale-oil development.

While evolutionary technology is to be expected in the fields of exploration techniques, drilling, and recovery, the cost of crude, especially offshore, still could increase in the future and thus hasten the shale-oil development. By contrast, if exceptionally low-cost or efficient methods were developed in any of these technologies, the cost for producing crude oil might be reduced significantly and shale-oil development delayed still further.

A research effort also is under way on methods for converting coal -- a resource also in abundant supply -- into liquid fuels. The major problem faced by coal is the large volume of costly hydrogen required for such conversion. The advantages that coal may have over oil shale, however, are: (1) the great reservoir of coal-chemistry knowledge accumulated over the years; (2) better product yields of over 100 to 150 gallons of oil per ton for coal compared to 25 to 40 gallons per ton for oil shale; (3) a smaller waste disposal problem; and (4) proximity of major coal deposits to large fuel markets. Table 6 contains preliminary cost estimates for converting coal and gas to liquid fuels based on the technical-performance claims made by various industrial firms. Not enough information is available to make independent engineering estimates on the same basis as the other costs estimated in this report; hence, these values are not subject to direct comparison. The wide range of values indicates a probable high degree of uncertainty.

Table 6. - Cost estimates for converting coal and gas to liquid products
(Plant size - 35,000 bbl. per day)

Process	Estimated Capital Investment (million dollars)	Total annual operating cost (million dollars)	Operating costs after credits (million dollars)	Operating costs per barrel of oil	
				Before byproduct credits	With byproduct credits
A	128.6	50.0	43.5	3.91	3.41
B	136.3	41.1	18.8	3.22	1.47
C					
Coproduct	121.4	60.9	29.0	4.77	2.27
No Coproduct	117.7	60.0	42.4	4.70	3.32
D 1/	474.9	80.7	66.2	6.31	5.18
E (gas)	219.3	58.1	52.0	4.55	4.07

1/ "Per stream day". (Other estimates are on the basis of calendar-day).

The value of a semirefined shale oil in Colorado has been estimated at $3.08 per barrel.[1/] With the 1972 technology described previously, the cost of production is estimated at $2.98 per barrel (after byproduct credit) using 30 gallon-per-ton shale and a 12 percent discounted cash flow (DCF), and exclusive of resource costs. Since the value of the semirefined shale oil, $3.08 per barrel, falls in the range of possible error in the cost estimate ($2.68 to $3.28 per barrel, assuming that all the technologic assumptions are

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[1/] This value was developed by estimating the value of the semirefined crude delivered to a refinery and subtracting the estimated pipelining costs from Colorado. The physical and chemical properties of the semirefined crude were supplied to two large refiners and the value selected was the average of the values which were assigned by these refiners.

accurate) the first shale-oil plant would be marginally attractive at 12 percent DCF without inclusion of resource charge. However, because of the high technological and other risks involved in such a capital-intensive venture and the rapid obsolescence that can be expected for this first plant, a potential investor may desire a higher DCF.

Since the first plants are expected to use technology particularly suited to the oil-shale deposits largely in private hands, it would be most appropriate that industry undertake the first ventures. The oil industry is accustomed to making large expenditures for advanced technology. To the extent that Federally-owned resources of similar nature are needed to fill out economic operating units or to provide a resource base sufficient to support a production plant, the Federal Government should commit itself to the offering of competitive leases or to enter into "blocking-up" arrangements to enable private industry to move ahead.

With experience gained in the operation of a first-generation plant, it is anticipated that a second plant could be constructed which would permit production of shale oil at more economically attractive levels. The technology is fairly well known and it is believed that operation of a single plant would provide the information necessary so that a second-generation plant could produce shale oil at lower cost.

Moreover, the investments in the mine and in the semirefining plant could be used in a second generation plant. These represent about 65 percent of the total capital investment.

As an alternative, a privately financed plant module of 5,000 barrels per day of semirefined crude oil capacity could be used to permit mining, retorting, and semirefining at a sufficient scale to permit more confident cost estimates, to improve technology, and to demonstrate and prove the technology of a full-scale retort. The cost of a shale-oil plant of this size has been estimated at $34 million instead of $138 million for a full-scale plant.

Private construction of a full-scale plant or a module is the preferable method of proving retorting and related technology. If such private investment is not forthcoming, however, the question will arise as to the appropriate Federal policy and action in the development of the oil-shale resource. In that event, the Federal Government should seek to determine the reasons for industry's inaction and reassess all aspects of Federal oil-shale policy.

The economic development of the thick deep seams that are largely Government-owned will require still further research and development. A Government research program for developing new mining systems for these seams may be needed. Such a program might be justified on the basis of the increased value that the Government-owned resources would acquire as a result of the successful development of a mining system for the thick beds.

In situ retorting, using either nuclear or conventional methods of fracturing now is being explored. The potential of underground mining systems capable of economically extracting shale oil at reasonable percentages of resource-recovery from thick deep seams is being evaluated.

5. The Development of a Shale-Oil Industry

A. Public policy and oil shale

While much has been written which deals with the policies and goals of the mineral leasing program in a general way, there is little information available regarding specific goals. Neither the Mineral Leasing Act of 1920 nor succeeding legislation provides any specific itemization of the goals of mineral disposal. Alternative leasing policies evaluated in this report are on the bases of economic efficiency and of achieving fair market value return to the Government.

(1) Efficient resource allocation among competing uses and between different points in time raises the standard of living of the Nation. If perfect competition prevailed, if there were no external costs or benefits, and if there was no interference with free markets, the operation of the market would yield optimum resource allocation. Where such conditions do not prevail, it should be an objective of Government policy to create conditions of resource use that approximate as closely as possible those that would result from a perfectly competitive market.

(2) It is Government policy that Federally-owned resources or property be leased or sold for fair market value. The

Government must obtain fair market value as a matter of equity between the public owners of resources and the private users, as well as to achieve efficient use of the resources in the economy, by encouraging its use where its value is highest.

B. Bidding methods

Table 7 summarizes the bidding methods considered and indicates the advantages and disadvantages of each. It should be noted, however, that at the earliest it will be at least 5 years before leasing for commercial production is expected because solutions first must be found to the ownership and resource value problems, and the economics of existing technology must be demonstrated.

Based upon analysis of competitive bidding experience in other resource areas, it appears that during the initial years of development, there may be few competitors and competition may be weak. Under such conditions, it probably would be appropriate to use sealed bidding procedures with an unannounced refusal price. However, after the industry becomes established and entry barriers due to technological uncertainty are reduced, oral bidding with an announced refusal price may be preferred.

Given the assumption that the Federal Government should not enter the oil shale business to compete with private enterprise as a producer of oil from shale, but rather should lease its

Table 7 - Alternative Competitive Bidding Systems

Type	Advantages	Disadvantages
Oral bidding	1. Buyer can react to bid of others.	1. If competition is limited there may be lower prices. 2. Vulnerable to collusive practices.
Sealed bidding	1. Where competition is weak, bids may be higher than under oral bidding.	1. Buyer must estimate the value and the strength of the resource competition in the absence of complete knowledge. 2. No "second chance" to bid.
Method		
Royalty bidding on percent gross value.	1. Minimal capital barriers to entry. 2. Administration relatively simple. 3. Operator pays only for resources used.	1. Can result in misallocation of resources. 2. Difficult to obtain fair market value when technology and costs are not well known.
Bonus bidding	1. Easy to administer. 2. Provides maximum incentive for efficient resource allocation.	1. Raises cost barriers to entry (unless accompanied by delayed payment schedule). 2. No means of sharing high profits or losses & therefore is not suitable where great uncertainty prevails.
Profit sharing	1. Operator pays only if his operations are profitable. 2. Capital barriers to entry are minimal. 3. Resource misallocation is minimized.	1. Difficult to administer. 2. Requires additional Government involvement in internal affairs of business.

oil-shale resources to private industry for development and processing, two problems are encountered: (1) the need to select the lessee, and (2) the need to determine the price of the resource. These two problems must be solved in a manner consistent with the goals of optimum resource allocation and equity between resource owners and users. Further, resource allocation efficiency requires that administrative costs including expenses of adjudicating disputes be included in cost calculations.

(1) Competitive vs. noncompetitive leasing

Under existing regulations the Department of the Interior is authorized to lease oil and gas lands, which are not within a known geologic structure of a producing oil or gas field, to the first qualified applicant. The problems and litigation which have arisen as a result of the competition to be the first qualified applicant demonstrate quite clearly one of the major disadvantages of a noncompetitive leasing system.

From 1920 through 1963, there were over 400 Interior Department cases involving noncompetitive leasing published in Interior Department Decisions but none on competitive leasing. Although these publications do not reflect all of the cases in which the Department has been a litigant, it is still significant that no case dealing with the administration of competitive leasing has ever been reported. The conclusion is that legal problems resulting from noncompetitive leasing procedures are much more complex and involve more administrative problems and precedents in determining to whom the resource is to be leased. In an administrative leasing system, the unsuccessful company often concludes that its failure to obtain a lease was due to administrative discrimination. On the other hand, an appropriately administered competitive system selects the lessee in the impersonal market place on the basis of an objectively determined high bid. In addition to the administrative problems, noncompetitive leasing can fail to allocate resources to qualified operators resulting sometimes in unproductive and detrimental speculative acquisition of public resources and in acquisition by inefficient operators. Noncompetitive systems tend to produce revenues below a fair market value because administrative rationale in determining fair market value is no substitute for the marketplace.

The best method of transferring the mineral resource to the private sector, therefore, is by some kind of a competitive leasing system. Such a system probably would result in greater revenue to the Government, better serve industry's needs and contribute to a superior pattern of resource allocation.

(2) Alternative competitive bidding systems

In competitive bidding a choice must be made between sealed and oral auction bidding. The principal factor which should determine the bidding system is the probable vigor of competition. Where a market contains many bidders, the interest of the seller is well protected by either oral or sealed bidding, and the choice of bidding procedure can be based on other factors. However, where there are few bidders and competition is unreliable, the choice of bidding system becomes crucial. In the initial years (perhaps 10) of an oil-shale industry, the number of bidders may be limited by: (1) lack of an established and known technology; (2) high capital costs; and (3) other energy market uncertainties.

From the bidder's point of view, the principal advantage of oral bidding is that each bidder can hear and see the bids cast by all others. Consequently, he can: (1) make an initial bid at the lowest acceptable level; (2) cast successively higher bids if necessary to obtain a given resource; and, at the same time, (3) avoid "leaving money on the table." This expression refers to a substantial difference between the high bid and the second high bid in closed bidding. From the sellers' point of view, the primary advantage is that bidding by oral procedures may produce a higher level of receipts especially where competition is vigorous. On the other hand, where competition is weak or unreliable, oral bidding can produce either highly competitive sales or noncompetitive sales. Given oral bidding procedures where only one bidder is present, interested, and qualified to bid, the lease offered may be obtained for the lowest amount acceptable to the seller (the refusal price). A single bidder will never bid against himself. Even where two or more bidders are present, competitive bidding may not take place for numerous reasons including situations where either implicit or explicit collusion exists. From the sellers' standpoint, the problem of oral bidding under conditions of few bidders is lack of bidding intensity. Such bidding turns to the advantage of the buyer because he has no uncertainty about how much his competitors have bid and can test their willingness to bid higher.

Sealed bidding procedures, on the other hand, always contain an element of uncertainty due to potential competition. Even if a collusive agreement is in effect among bidders, the specter of an outsider submitting an unannounced sealed bid may, and often does, force a serious bidder to submit a higher bid which he calculates more nearly approximates "fair market value." It could be concluded that, where competition is known to be weak, sealed bidding procedures will produce a higher selling price than will oral bidding.

Under oral bidding, the interests of the seller might be protected against the single bidder situation or the collusive situation by setting an announced refusal price closely approximating the appraised "fair market value." However, objections are often raised against "high" refusal prices, especially where competition is weak. As an alternative the seller can withhold refusal price information but retain the right to "refuse any and all bids." This provides some protection for the public interest, but such protection is more limited. It would be exercised after the identity of the high bidder is known. It is expected that the bids that may be refused would be limited to those that are most obviously and most unreasonably low relative to appraised value. Only clearly weak bids are rejectable and the rejection defensible. Accordingly, those buyers who obtain resources under noncompetitive conditions can receive bargains under oral bidding conditions even though the bid equals or exceeds the "refusal price." Uncertainties associated with estimating resource values relative to actual fair market value can result in significant variance. Those bargains come at the expense of the owners of resources. Sealed bidding, with its element of uncertainty, even though there may be limited competition, offers some additional protection for the public.

(3) Alternative objects of bidding

In addition to selecting a bidding system (oral or sealed), a choice must be made between three objects of bidding: (1) the royalty, (2) the bonus, and (3) a profit share to be paid by the lessee to the lessor.

(a) Royalty bidding

Royalty payments tend to result in misallocation of resources. A royalty payment is levied as a charge on a unit of output (a barrel of oil). It is added to the other costs of production, independent of profitability. Production will be halted when the cost of an additional barrel exceeds the expected revenue unless diligence and performance requirements of the lease prohibits such action. If a fixed royalty charge is levied for the entire term of the lease, the "close down" point will be reached before the resource is exploited to its economically optimum level. Consequently, valuable resources are not recovered fully and, to that extent, misallocation of resources results. The higher the royalty, the greater the resource misallocation problem.

To avoid the misallocation for parcels containing known amounts of oil, a full royalty might be set on the first units of production, and a declining royalty on a terminal portion. This would provide incentive to achieve greater mining and retorting efficiency since any increase in output beyond the full royalty point would be at a lower royalty. It must be recognized, however, that this system involves a risk of prediction - the recoverable quantity may be far larger than originally estimated. A declining royalty reduces resource misallocations and permits a sharing of any potential "windfall."

Royalty bidding and royalty payments do not present insurmountable administrative difficulties. However, a point in the production process must be agreed on as the point where the gross value will be estimated for the purpose of applying the percentage royalty. Products in addition to shale oil, such as dawsonite and nahcolite, can be accommodated in the same manner.

(b) Bonus bidding

Under this system the successful bidder would be determined on the basis of the highest bonus bid received from the qualified applicants. This method is currently being used by the Bureau of Land Management in its competitive sales of leasable materials.

Bonus bidding avoids any interference with optimum resource allocation. Under a pure bonus system (i.e. not accompanied by a fixed royalty requirement) the high bidder makes the agreed-upon lump sum payment and obtains the right to recover all the resources leased. However, it offers no means of sharing windfall gains and losses between the operator and the resource owner.

If immediate payment is required, bonus bidding may raise barriers to entry because of the large capital requirements. One means of lowering the entry barrier due to the bonus payment would be to include a delayed bonus payment schedule in the lease contract.

In the case of oil shale a combined bonus and royalty bidding system could have an advantage as oil companies, the most likely bidders for shale resources, are accustomed to its use. Such bidding under conditions of great uncertainty has been used for the Outer Continental Shelf and gas lease sales offered by the Bureau of Land Management since 1954.

(c) Profit share bidding

Under this system, the buyer would bid a percentage of the net profit from oil shale mining and retorting operations which he would pay to the Government. The principal advantages of this system are: (1) payments depend on profitable operations, (2) barriers to entry are lower than with bonus bidding, and (3) resource misallocation is less than with royalty though greater than with bonus bidding. The system is most suitable for situations characterized by high uncertainty. Windfalls are shared by lessee and lessor.

Since payments for the resource are made only after profit has been realized, rather than at the point of auction as in bonus bidding, the barriers to entry due to the resource cost are low. Further, since the resource cost declines as marginal resources are reached, the misallocation problem associated with royalty payments is slight. The incentive to operate efficiently is high, but not as high as under bonus bidding since some of the gains must be paid to the Government.

The principal disadvantages of profit share bidding are: (1) it is difficult to administer; (2) it requires extensive involvement of the Federal Government in the internal affairs of business; and (3) the most efficient producer will not necessarily be the high bidder.

Since the resource cost is a function of production cost and revenue, the lessor must exercise some control over expenditures by the lessee. A company would have an incentive to charge to mining and retorting a maximum of the parent company's overhead costs. The amount of overhead fairly chargeable to mining and retorting cannot be determined with precision and is rather subjective. A vertically integrated company would have an incentive both to overstate mining and retorting costs and to understate the value of retorted shale, shifting profit forward or backward to other levels in company operations. To avoid these abuses, careful auditing of company records would be required and accounting standards must be stated precisely in advance of the auction.

Profit share bidding is not as effective in selecting the most efficient producer as bonus bidding or royalty bidding. In either of the latter two cases, the bidder must estimate his costs and revenues and determine the residual value. This estimated residual becomes the basis for calculating the maximum bid. The most efficient producer, by definition, has the highest residual and, therefore, is in a position to cast the highest bid. If there is a direct relationship between this residual and the amount bid, then the most efficient operators are the winning bidders. In contrast, the profit share bidding system selects the bidder who is willing to pass the largest profit share to the Government. It permits an inefficient producer to bid a higher share of a smaller profit and thereby win the lease.

(4) Miscellaneous considerations

(a) Number and size of leases

Under current regulations, maximum lease tract size is limited to a fixed number of surface areas for each producer. The thickness and quality of the oil shale deposits vary, however, and any limitation on lease tract size should not be based on surface acreage alone. Instead, an economic production unit might be offered. This leasing unit would be based on the quantity of reserves necessary to support a typical sized mine and plant facility for, for example, 20 years (for underground mining methods). Adjustments in lease size might also be required to accomplish other goals, such as avoiding bisecting a water course or providing reasonable ease of access. Space for location of a plant site needs also to be provided.

Where the oil-shale deposit could be exploited by open pit mining, a larger tract size and longer reserve life may have to be specified.

If a producer needed additional reserves to amortize a larger plant, he could nominate a contiguous lease unit. This unit might then (at the option of the Secretary) be put up for competitive bidding. The nominating company would have certain economic advantages in the bidding since it owned the adjoining lease parcel.

It may not be necessary as a matter of economics to limit the number of leases held by one person or firm since the rental system specified below would make the holding of unproductive leases uneconomical.

(b) Rental

In order to avoid speculation on the initial leases, the successful bidder could be required to pay a significant graduated annual rental, creditable against royalties. The amount of the rental would have to be considerably above the $0.50 per acre currently specified in the law. This could be based on the estimated number of barrels of oil equivalent in place rather than on the total acreage each producer holds under Federal lease. Total acreage is meaningless because of variations in the thickness and quality of the resource. Thus, an acreage rental system is not equitable.

(c) Time limitation

As a further deterrent to lease speculation, leases may be limited to a given period of time. Perhaps the expected period of production would be suitable.

(d) Need for pre-sale information

In order that both the Government and the resource purchaser may have confidence that the bids reflect fair market value, regardless of the system used, sufficient knowledge of the deposit and the costs of exploiting it must be obtained. It is difficult for the Department to manage the mineral estate intelligently when little is known about the quantity or quality of the resource.

Before each potential lease parcel is offered, the Government should finance geologic investigations to the extent necessary to reasonably define the content of the oil-shale deposit. This also would allow better management and would facilitate the determination of the extent of occurrence of other associated minerals.

(e) Serial versus non-serial leasing

Under a simultaneous (non-serial) offering system, the potential producer cannot be sure that he will not over-commit himself by being the successful bidder on several lease tracts. By offering leases serially, the bidder and his competitors are given the opportunity to determine success or failure in previous bidding before commiting additional funds for other lease parcels. In addition, parcel offerings make it less likely that "fishing bids" will be successful, i.e. low bids offered on a multiplicity of tracts in the hope some will not be bid on by others.

Leases, therefore, could be offered serially either at the discretion of the Government or by nomination by the companies. The resource manager would not be obligated to offer for competitive leasing every unit nominated.

(f) Other possible requirements

((1)) To facilitate development of the resource, the transfer of leases among lessees could be allowed subject to antitrust review by the Justice Department.

((2)) A seller's right of access to production-cost records of each lessee could be retained on a confidential basis by the Government in order to be able to obtain accurate and current cost data for use in establishing minimum bids as necessary. To reduce the costs of obtaining such data, this right might be exercised on a sampling basis.

((3)) A renegotiation provision introduces some uncertainty into the matter of ultimate cost to the lessee which will tend to reduce the commitment which firms will be willing to make. There should be no need for contract renegotiation during the initial lease period if sufficient resources are leased for the anticipated life of the commercial plant. However, provisions for renegotiations should be included at least in the early leases in order to provide an opportunity to compensate for changes in technology, resource values, etc. that might occur over a 20 to 30 year period.

((4)) An effectively competitive bidding system will provide better safeguards than can generally be expected through bidder eligibility requirements.

((5)) Specific requirements for research and development should not be included in production leases. Instead companies should plan their own research and development and adjust their bids accordingly, thus retaining an incentive for efficiency and managing their own programs without Government involvement.

((6)) There could be a requirement for diligence in that leases would terminate after a stated period of years (depending upon the time needed to get into production) unless by that time production was on a commercial basis.

(5) Summary and conclusions regarding leasing

The disadvantages of a noncompetitive system include high administrative costs, a propensity toward speculation, and the substitution of administrative judgment for the workings of the marketplace. In addition, such a system would not be readily accepted by industry so that its use might retard development of the oil-shale resource.

It can be fairly concluded, therefore, that a competitive bidding method ought to be used. Since sealed bidding offers greater assurance of obtaining fair market value where competition is weak (the condition expected at the initiation of oil-shale bidding), and is somewhat less vulnerable to collusion, the sealed competitive system probably would be best at least initially. However, when competition for leases becomes strong, oral bidding might result in a greater return for the resource.

A combination of bonus bidding (with a refusal price and a high graduated rental requirement) and a modified royalty payment appears to offer a good compromise among the bidding alternatives. The refusal price should approximate the estimated fair market value to protect the public interest against inadequate competition. A high annual rental should be required to stimulate early development and production. Rental payments due in any one year could be applicable toward royalty payments due in the same year. If the bonus bidding appears to be a barrier to entry due to large capital expenditures, provision could be made for installment payments.

To promote optimum resource utilization and to mitigate "windfall" potentials, a declining royalty rate should be considered after a specified amount of the resource has been utilized. The point in the production process where royalty will be charged still must be determined. Preliminary evaluation indicates that this royalty should be on the oil shale and associated minerals in place, as the processing options selected will cause the end products and their value to vary widely.

C. Regional impact

The impact of any new industry, especially one highly concentrated geographically in a largely rural region, would depend both on the rate of development and the industry's ultimate size. Adequate housing, schools, libraries, transportation and communication systems, water and power services, and other community requirements would have to be provided to meet the needs of both the new industrial plants and the related urban growth.

The labor force required to man the plants and provide support services would be large enough to change the social and economic patterns of the area that now has a population of 72,000. It has been estimated[1] that a million-barrel-a-day oil-shale industry would have the following effects:

1. Generate an annual payroll of about $280 million.
2. Employ 15,700 people in construction and operation of the plants and require a total of 27,000 other people who will be associated in support of the industry.
3. Increase the total population by 115,000 people.

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[1] Ryan, J. J. and Welles, J. G., Regional Economic Impact of a U.S. Oil Shale Industry, Denver Research Institute, University of Denver, Denver, Colorado, 1966, 81 p.

Careful advance planning and significant capital investment and operating costs would be required to ensure orderly development of the area. This would require an understanding at all levels of the magnitude of these physical and financial demands. Local community planning for land use should be completed in advance for adequate development of supporting and public facilities.

D. Water resources

(1) Requirements

The mining, crushing, retorting, and partial refining processes of a 1 million barrel per day shale industry in Colorado, using the 1972 gas-combustion plant (described earlier), would require a diversion of about 145,000 acre-feet of water annually to support the industry and to meet related urban demands (if the associated minerals are not processed). Of that amount, from 60,000 to 95,000 acre-feet of water would be consumed. (table 8)

Some water would be produced during the oil-shale retorting and the amount shown in table 8 (10 gallons per ton) could be expected from either the TOSCO or gas-combustion retort. Since this water would have a relatively high total dissolved-solids content, it would not be of potable or irrigation quality, but it could be used to control dust when the waste material is dumped -- in which case it would be utilized without causing significant pollution. If such use is not feasible, the water produced during retorting would have to be impounded or treated before being discharged into streams or otherwise disposed.

Table 8. - Estimated annual water requirements at various semirefined shale-oil production rates
(Thousand acre-feet per year)

	Shale-oil production, thousand bbl/day	
	35	1,000
Water diverted:		
Basic operations 1/	3.5	100.0
Urban use 2/	1.1	36.8
Solid waste disposal	0.9	25.0
Credit for water produced 3/	-0.5	-16.8
Net diversion requirement	5.0	145.0
Water consumed:		
Basic operations	1.4-2.6	40.0-75.0
Urban use	0.4	12.3
Solid waste disposal 4/	0.4	8.2
Net water consumed	2.2-3.4	60.5-95.5
Water returned 5/	2.8-1.6	85.0-45.0

1/ Includes mining, retorting, and partial refining and is based upon a feasibility study prepared by the Bureau of Mines. Water consumed depends upon methods selected for processing and is assumed to range from 40 to 75 percent of water diverted.

2/ Consumption estimated at one-third of water diverted.
Source of Data: Ryan, J. J. and Welles, J.G., Regional Economic Impact of a U. S. Oil Shale Industry. Denver Research Institute, University of Denver, Denver, Colo., 1966, pp. 52-55.

3/ Basis: Gas-combustion retort which produces about 10 gallons of water/ton of shale retorted. Assumes all water produced will be used to control dust; hence, these amounts of water are deducted from diversion requirement.

4/ Represents the difference between amount needed and that produced during retorting.

5/ At acceptable water quality standards.

Using the best data available on the concentration of associated minerals, the volume of water required to extract alumina and soda ash from the shale retorted by a 35,000 barrel-per-day semirefined shale-oil plant is estimated at 6,400 acre-feet per year when 0.6 million tons of alumina and 1.7 million tons of soda ash are recovered. Neither this water requirement nor the additional water that would be needed to support additional urban population associated with such a minerals industry are included in table 8.

(2) Availability

Water from the Colorado River or its tributaries would be used to supply the needs of the area and the amount that can be consumed is restricted by existing compacts between the States in the Colorado River Basin and by treaty with Mexico. That available for the Upper Colorado Basin for depletion is estimated by the Bureau of Reclamation to be 5,800,000 acre-feet per year assuming the Upper Colorado Basin meets half of the Mexican Water Treaty delivery.

As shown in table 9, water is not a critical factor in either Utah or Wyoming since there are more than 200,000 acre-feet in each State available for consumptive use by an oil-shale industry even if all of the committed water use takes place by the year 2030. This quantity of water could support an industry of 1 to 2 million barrels per day in each State; however, this available water could be allocated to uses other than oil shale should they develop in the future.

Table 9. Present and future water use in Wyoming and Utah:[1]
(thousand acre-feet annually)

	Wyoming		Utah	
	1975	Ultimate (2030)	1975	Ultimate (2030)
Apportioned ultimate depletion	805	805	1322	1322
Present use	-267	-267	-581	-581
Committed for future use	-123	-228	-117	-213
Evaporation from storage units	- 92	- 92	-152	-152
Credit for water salvage	+ 23	+ 23	+ 38	+ 38
Committed for proposed projects	--	- 31	- 50	-147
Potential water available for depletion for oil-shale development	346	210[2]	460	267[2]

[1] Bureau of Reclamation Estimates.

[2] Assumes the Upper Basin obligation to contribute to Mexican Treaty deficiency

Availability of water in Colorado in terms of consumptive use for oil-shale development is shown in table 10 for two assumed conditions regarding the Colorado River Basin. As the table indicates, under these alternative assumptions, between 86,000 and 456,000 acre-feet of water would be available annually for consumptive use.

A comparison of the data in table 10 with those in table 8 indicates that under the most restrictive conditions, there is enough water to support a Colorado oil-shale industry of about 1 million barrels per day if no associated minerals are processed. Under the less restrictive condition, water potentially would be available to supply a Colorado industry of up to 5 million barrels per day. (Present US petroleum production is

Table 10. - Availability of water for oil-shale development in Colorado--effect of current legislative proposals[1]

(Thousand acre-feet per year)

Item	Case I		Case II	
	1975	Ultimate (2030)	1975	Ultimate (2030)
Not presently used or committed	744	489	744	489
Would be committed by proposed projects	30	477	30	80
Remaining for use	714	12[2]	714	409[2]
Present or proposed use for oil shale development:				
Green Mountain Reservoir water under contract (TOSCO)	7	7	7	7
Ruedi Reservoir water available for contract	20	40	20	40
West Divide Project proposed M&I water	--	27	--	--
Total present or proposed use for oil shale	27	74	27	47
Total potential water available for depletion for oil shale development	741	86	741	456

Explanation:

Case I - Based on authorization and construction of the projects included in H.R. 3300, 90th Congress, (Colorado River Basin Project).

Case II - Situation without above projects.

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[1] Bureau of Reclamation estimates.

[2] Assumes Upper Basin obligation to contribute to Mexican Treaty deficiency.

about 9 million barrels per day). The development of an industry to process the associated minerals would compete for water with the shale-oil industry. The size of the combined complex may be limited by water availability, with the use being determined by the most favorable overall economics.

(3) Values

Based on existing patterns of water use in the Colorado Basin, it is estimated that an acre-foot of water has an average benefit value of $18.00, net of all costs required in delivery and use. This figure represents a composite amount based on the present mix of uses and the values for each use. The amount would be altered by shifting uses and by changes in price assumptions.[1]

This benefit value is not necessarily representative of the market value of water, since it is possible that water rights associated with private irrigation use may be purchased at substantially lower cost. Also storage water may be purchased from Federally constructed reservoirs. For example, the contract between the Colony Development Company and the Government for water for oil shale use stipulates charges ranging from $8.50 to $10.46 an acre-foot for water released from the Green Mountain Reservoir. As demands for water increase, and as storage sites become more costly to develop, it is likely that water costs could range from $12 to $20 an acre-foot.

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[1] Source, Bureau of Reclamation.

E. Impact on supply from other energy sources

Oil shale will have to compete with other existing energy sources and with other alternative methods for producing liquid fuel substitutes. The development of a shale-oil industry could affect the rate of petroleum exploration and eventually could result in a reduction in the United States productive capacity for liquid petroleum.

With a "sunk" investment in exploration and drilling, petroleum will continue to be produced from those wells where the out-of-pocket operating costs do not exceed the price of petroleum.

Commercial shale development may have some bearing on future supplies of natural gas. To the extent that shale oil replaces crude oil, the resources of producing industries could be directed away from prospecting for oil. Because the initial stages of geological and geophysical exploration are nonselective between crude oil and natural gas and even subsequent drilling is only partly selective, any lag in exploration for oil will tend to reduce the discovery rate for natural gas -- whether or not it is associated with crude oil reservoirs.

Liquid fuels already are beginning to be produced from tar sands on a commercial scale in Canada and the technical feasibility of converting coal and gas to liquid fuels has been established for many decades. Continuing research is under way to further reduce the cost of these processes. The commercial development of any of these alternative potential sources of fluid energy will require both large-scale operations and heavy capital commitments.

F. Effect on oil imports

As reflected in this study, shale-oil production (but with no charge for the resource) may now be marginally attractive at current domestic prices. Domestic oil prices, however, are, in part, dependent on continuation of existing import policies. At least in its early years the emergence of a United States shale-oil industry might appear to be dependent upon either a continuation of import controls or upon other measures which would permit it to compete with other domestic crude sources. Should large scale shale-oil production occur, questions of the continuation of the oil import program will emerge. Examination of oil import policies or other alternatives is, however, beyond the scope of this report.

If the oil import program continues, two basic questions are raised: (1) how shale oil should be used in calculating oil import quotas, and (2) how it should be treated in allocating these quotas to eligible importers. These questions affect not only the economics of shale oil but also shale's competitors.

(1) Under the present oil import program, imports[1] into Districts I through IV[2] are limited to 12.2 percent of the U.S. production of crude oil and natural gas liquids in those districts. If this program remains in effect when the production of oil from shale becomes commercial, a determination will have to be made of how shale oil is to be treated in the import program. Oil from shale could be added to crude oil and natural gas liquids produced in the United States in determining the overall size of the oil import quota. This would place shale oil on the same basis as crude with respect to oil import quotas, making the quota 12.2 percent of U. S. oil production, whatever its source (coal or tar sand oil would presumably be given the same treatment).

(2) If shale oil is not included as an eligible input for oil import quota allocation, refiners would have an economic preference for crude oil, other things being equal, because of the import allocations which its use would generate.[3] The preference would be reflected in a lower market price for shale oil

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[1] Other than residual fuel oil.

[2] Districts I through IV include all States except Washington, Oregon, Nevada, California, Arizona, Alaska, and Hawaii.

[3] The concept of auctioning oil import tickets has been proposed in lieu of the present method of making allocations. Under these conditions the refiner should have no preference for crude oil.

of about 11 cents per barrel [1] and would serve to discourage the development of a shale-oil industry. For large refineries, the differential would be as little as 6 or 7 cents per barrel since quotas are allocated on a sliding scale with a smaller quota to the larger refiners.

If shale oil is to be included as an eligible refinery input, a determination will have to be made concerning the form in which it acquires eligibility as crude oil. The issue is whether to use the point where it is partly processed, or where it is ultimately refined. This becomes significant if these operations are conducted by different operators.

G. Effect on regulatory practices

The State regulatory and conservation agencies in the principal crude oil producing states might react by adjusting programs to maintain their market for crude petroleum to meet the competition of an emerging shale-oil industry. Should the shale oil become a significant factor in the energy mix, questions of continuation of State oil production controls will doubtless emerge. Consideration of these and related problems is beyond the scope of this report.

H. Federal tax treatment of oil shale

According to existing Federal Internal Revenue Service rulings, income from commercial exploitation of oil shale would be eligible for depletion allowances under the Federal income tax. Such allowances could be based either on "cost depletion" or on "percentage depletion" -- amounting to 15 percent of the gross value of oil shale after it is mined and crushed but prior to retorting. This is equivalent to about 5 cents per barrel of shale oil after taxes. Spokesmen for oil-shale interests have argued that the allowable percentage depletion should be 27-1/2 percent (the same as for petroleum) and that it should be based on the value of the shale oil after its extraction from the oil shale. This is equivalent to about 40 cents per barrel of shale oil after taxes. Others have argued that since the quantity of shale oil recoverable from a given formation can be determined with reasonable accuracy in advance of its production, there should be no depletion allowance. Resolution, or even detailed analysis of this issue, is beyond the scope of this report.

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[1] Crude oil imports are about 9 percent of total demand so the value of an import quota to a refiner is 9 percent of $1.25 (current value of an import ticket) or 11 cents.

I. Existing legislation for leasing of oil-shale lands and for research

(1) Mineral Leasing Act

The legislation authorizing leasing of oil-shale lands is the Mineral Leasing Act, 30 U. S. C. 241. The pertinent provisions of the oil shale section are as follows:

> No lease shall exceed 5,120 acres of land, to be described by legal subdivision of the public-lands surveys;

Leases may be for indeterminate periods upon such conditions as may be imposed by the Secretary of the Interior including covenants relative to methods of mining, prevention of waste, and productive development;

An annual rental of precisely $0.50 per acre per year must be charged;

A royalty in an amount specified in the lease may be charged;

The annual rental is to be credited against royalties accruing for that year;

Royalties are subject to readjustment at the end of each 20-year period by the Secretary of the Interior;

The Secretary may in his discretion waive the payment of any royalty and rental during the first 5 years of any lease;

Not more than one lease shall be granted to any one person, association, or corporation.

In addition, the oil-shale section incorporates by reference other provisions of the Mineral Leasing Act. For present purposes those most relevant are as follows:

No person, association, or corporation may take hold, own, or control at any one time an interest as a member of an association or a stockholder holding a lease which, together with his other direct or indirect interests, exceeds in the aggregate more than the maximum number of acres allowed to any single lessee. Thus, for oil shale, the total direct and indirect holdings for any person, corporation or association in Federally-leased oil-shale lands would be 5,120 acres. However, pro rata holdings of individuals in associations or corporations are not counted for this purpose unless the holdings are 10 percent or more of the stock or other instrument of ownership or control of such association or corporation. 30 U.S.C. 184(e).

No lease may be assigned or sublet except with the consent of the Secretary. 30 U.S.C. 187.

The Secretary in his discretion may permit written relinquishments which upon acceptance relieve the lessee of future obligations under the lease. Surrender of legal subdivisions of leases may also be permitted with the consent of the Secretary. 30 U.S.C. 187.

The money to be received by the United States from leasing of its oil-shale lands is to be paid into the Treasury, and that total (except for Alaska) is to be divided on an annual basis, as follows (30 U.S.C. 191):

37-1/2 percent to the State in which the leased land is located;

52-1/2 percent to the Reclamation Fund;

10 percent to miscellaneous receipts.

(2) Investigations, studies and experiments pursuant to the Public Land Administration Act

The Public Land Administration Act of July 14, 1960, 74 Stat. 506 (1960); 43 U.S.C. 1361-1374, reads in pertinent part as follows:

§1362--The Secretary of the Interior may conduct investigations, studies, and experiments, on his own initiative or in cooperation with others, involving the improvement management, use, and protection of the public lands and their resources under his jurisdiction. P.L. 86-649, Title I, sec. 101, July 14, 1960, 74 Stat. 506.

§1363--The Secretary of the Interior may enter into cooperative agreements involving the improvement, management, use, and protection of the public lands and their resources under his jurisdiction. The provisions of this section shall apply only in those cases where the making of cooperative agreements for such purposes is neither expressly authorized nor expressly prohibited by other provisions of law. P.L. 86-649, Title I, sec. 102, July 14, 1960, 74 Stat. 506.

These sections give the Secretary wide latitude to conduct investigations and studies either on his own initiative or in cooperation with others with respect to the improvement, management, use, and protection of the public lands and their resources. The legislative history of the Act confirms this conclusion. [1]

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[1] House Interior and Insular Affairs Committee Report No. 1249, to accompany H.R. 7004, 86th Congress, 2nd Session, February 1960.

With respect to oil-shale studies and experiments, the Department is authorized to conduct investigations, studies, and experiments on its own or by cooperative agreement with others for the purposes mentioned in the Act. Some of the kinds of activities with respect to oil shale which could be carried out within this authorization include experiments to develop the value of the shale resource and to determine the effects on other resources, such as water, air, wildlife, and scenic values. The cooperation of private parties could be utilized in the conduct of these experiments, as well as in other types of activity, such as investigations to obtain mineralogical or economic information concerning the nature and extent of oil-shale deposits.

In addition, private parties could be permitted access to oil shale to engage in cooperative experiments with the Government, providing that such uses would not amount to leasing the oil-shale resource which must be accomplished only through the Mineral Leasing Act. Within that limitation, a variety of arrangements could be worked out under the Public Land Administration Act.

Under any such arrangements, experimentation should be limited to using areas and small amounts of the oil shale to the extent required for the specific experiment. Any such agreements should prohibit utilization of oil shale for purposes other than clearly designated research purposes, should not permit any commercial production and disposal of shale oil under this authority, should provide for full information disclosures to the United States concerning the conduct of experimentation, and should provide for public availability on appropriate terms of patentable technology developed in the course of experimentation by private parties.

J. Legislative problems

The provisions of the Minerals Leasing Act, as discussed above, may raise problems in the development of shale oil, although the existing legislation appears to be adequate to accommodate an initial program of test leasing under that Act. Any initial test leases clearly should disclaim any intent to set a precedent for future commercial oil-shale production leasing.

Obvious policy issues are presented by the revenue sharing and earmarking provisions of the Act. The earmarking provision calls for payment to the Reclamation Fund. Problems of revenue sharing with State and local governments are part of the general body of problems usually referred to as payments-in-lieu of taxes. Extensive consideration has been given to the complex and difficult subject of revenue sharing over a period of many years but without the enactment of general legislation. The subject involves both "public lands" as the term is generally used and various other classes of Federal lands, properties and activities. While resolving these issues are beyond the scope of this report, it can be concluded that full consideration should be given these subjects before production leasing is undertaken.

While not immediately essential, a review should be undertaken of the adequacy of other provisions of the Mineral Leasing Act such as the restriction of one lease per person, size of the lease, and the flat 50 cent yearly rental fee per acre.

K. Summary of needs for research

The Government has two distinct and important reasons for encouraging the development of a shale-oil industry: (1) the benefits to the Nation that could be achieved if development of the large latent resource is economically feasible; and (2) as land owner to utilize Federal natural resources in accordance with sound conservation and business principles and in the best public interest.

(1) Mining systems

In general, the privately owned oil-shale resources are near the outcrops and are particularly suited to the room-and-pillar mining methods that already have been tested extensively. Open-pit mining also should be possible depending upon overburden/shale ratios, but there have been no large-scale demonstrations of this method in oil shale. Federal holdings of this type of deposit are limited.

By contrast the thick, deep deposits of the Piceance Creek Basin are largely in Federal holdings, but satisfactory methods for underground mining of beds up to 2,000 feet thick with reasonable recovery of the resource have yet to be developed. Room-and-pillar mining might be adaptable to this thick type of bed. A honeycomb type of arrangement of the room and pillars can be conceived so that a minimum thickness of shale would be left between the horizons that are mined. The potential overall recovery of oil shale by this mining method is not known, but is not expected to exceed 50 percent, and may be much lower, and it would involve increased mining costs. Room-and-pillar mining could be used if only selected horizons within the 2,000-feet thick oil-shale deposits were mined. Development of new mining systems such as the "cut-and-fill" system described in chapter 4 is necessary if higher percentage of resources are to be recovered and reduced mining costs are to be achieved for utilization of these thick formations.

(2) In situ retorting

An in situ retorting method, either nuclear or conventional, eventually may be useful for utilization of various types of deposit. Nuclear in situ is suitable only for the thick deposits with adequate cover but there is a high degree of technical risk in the experiment since a large number of process variable are unknown. The size and shape of the chimney, the size distribution of the broken rock, the type and amount of radionuclides, the air pressure required to retort the shale, the efficiency with which the shale could be retorted from the chimney and the impact on water quality are some of the major unknowns that require testing. In addition, methods for recovering the shale oil from areas between chimneys (which may contain up to 85% of the total shale oil) still must be investigated and this may prove to be more difficult than recovery from the chimney itself. Because of the wide-spread interest and high technical risk, a joint venture of some 18 oil companies represented by CER, Geonuclear Corporation, in cooperation with the Government (Department of the Interior and Atomic Energy Commission) are actively negotiating an agreement to carry out a nuclear fracturing in situ test.

Non-nuclear fracturing followed by in situ retorting is believed to be applicable to both thick and thin oil-shale deposits. Various methods to obtain sufficient permeability to permit retorting have been investigated in a preliminary way by both the Government and industry. No commercial-scale tests have been conducted but indications are that additional technologic advances may be necessary before any process of this type can be an economic success. Research and development is being continued on methods of improving the process.

(3) Surface retorting and refining

While technologic advances in surface retorting undoubtedly will occur in the future, at least three types of retorts have been tested sufficiently so that commercial costs can be estimated. Two of these retorts were developed by industry and one by Government. Additional experimentation on other novel processes may reveal further improvements in retorting technology. Continuing research in this field is desirable.

Refining of crude shale oil is expected to use processes similar to those applied to crude petroleum which are highly advanced technologically. Most of the existing technology, with limited modification, is suited to shale oil; however, as new petroleum techniques are developed, modifications and improvements by industry can be expected to reduce costs further.

(4) Associated minerals

In the production of minerals associated with oil shale, several factors must be considered. Relatively pure beds of trona, about 10 feet thick, are now being mined in Wyoming, for example, and other deposits of sodium salts are known to be contained in the oil shale horizons -- some as beds of relatively pure sodium compounds and others commingled with oil shale. Potentially, the most valuable of the commingled sodium salts in Colorado may be dawsonite from which alumina has been produced in the laboratory. This is the raw material for the production of aluminum. With the relatively low concentration of dawsonite in known deposits, it does not appear that dawsonite can compete with other alumina sources using present technology. However, interest in dawsonite utilization is relatively new and methods for economic processing are considered to be within the realm of possibility with further research.

(5) Water pollution

Research must adequately cover potential water pollution problems, particularly those associated with plant residues, leaching of spent shale, in situ retorting and groundwater.

6. Study Conclusions and Recommendations

A. Title clearance

The title of much of the Federally owned oil-shale lands is clouded, but for the purpose of this study it has been assumed that most of the private claims on Government-owned land are invalid. If this assumption is incorrect, many of the related conclusions in this report would have to be modified. Title clarification is necessary in leasing of the lands; in "blocking up" ownerships; in making available surface rights necessary for access and other roads, building sites, and other development activities of a regional character; and for expenditure of public funds on geological investigations to aid in estimating resource values. Doubt as to ownership may also make it difficult to manage the land effectively and to protect other natural resources. Clouded title could be a deterrent to the establishment of an oil-shale industry if such title has not been clarified by the time these resources are required.

Actions already have been initiated on a number of test cases raising a total of 16 issues going to the validity of contested claims. It is expected that the establishment of legal guidelines on these issues will facilitate the disposition of all cases. Program increases for the Bureau of Land Management and the Office of the Solicitor are proposed in the budget for fiscal year 1969 to accelerate the clearing of title. In addition, the Department of the Interior has recommended the enactment of legislation providing for a recordation of mining claims with the United States Government, including a provision that failure to file within a specified time shall result in automatic cancellation.

B. Ownership "blocking-up"

Since intermixed land ownerships could present barriers to the development of economic blocks of oil-shale resources, provision should be made for consolidation of resource holdings either by leasing or land exchange, whichever best suits and protects the public interest.

There will be little need for ownership consolidation actions prior to production leasing of Federally owned resources as discussed in section E(2)(b) of this chapter. Where intermingled small tracts of private lands would encumber currently desirable Federal leasing actions which could otherwise be taken, land exchanges may be necessary.

The need for leasing or exchange of small Government-owned tracts intermingled with privately owned lands whose oil-shale resources are to be utilized could develop as soon as commercial production from such land is planned. In such instances, the

Government could assume a reactive role and await nominations for particular tracts that are proposed for either leasing or exchange:

If land exchange is used:

1. The fair market value of the offered private land must equal or exceed the fair market value of the selected public lands.

2. The exchange must not otherwise hinder the proper utilization and management of Federal lands.

3. The applicant receiving exchanged public lands must agree to preserve the quality of the environment and follow sound conservation practices for such lands.

4. The exchange must be necessary to form a rational economic unit. Generally the primary factor would be the extent to which the existence of "ownership islands" would be a barrier to optimum resource utilization.

5. The maximum amount of Federally-owned shale resource for any single land exhange would be limited to not more than 10 percent of the estimated amount (equivalent to approximately 50 million bbls. but not to exceed 320 acres) that would be required to support a full-scale production plant. If a larger amount of Federal oil-shale resource is involved, such Federal resources would be made available through competitive leasing procedures.

C. In situ experimentation

The nuclear in situ retorting approach is a high technical risk, high-cost proposal but, if successful, could develop the optimum technology for the thick, deep beds of the Piceance Creek Basin which are largely Government-owned. "Project Bronco," the cooperative nuclear explosive in situ retorting experiment proposed for joint sponsorship by Government and industry, is currently being negotiated. This approach would permit the eighteen participating companies to spread their risks and would reduce the cost to the Government -- the major resource owner. Justification for conducting the test includes the following:

1. The experiment should be conducted because it is required to establish the engineering parameters that will permit more accurate cost estimates. Only a test can provide the necessary data.

2. The social problems and costs of conventional retorting technology may have been underestimated and some of the problems may not be solvable by other than the nuclear explosive fracturing in situ retorting approach.

3. The information will be valuable in deciding whether mining using nuclear explosives would be economically attractive.

Funds are included in the fiscal year 1969 budget for the Federal share of this nuclear experiment, for continuation of non-nuclear in situ research, and for related research.

D. Proposed Government oil-shale investigation and research program

The proposed program is designed to:

1. Develop adequate geologic knowledge of the amount and quality of resources in place in order to:

a. Determine quantity and quality of oil shale, water and other mineral resources both separate from and directly associated with oil-shale formations.

b. Set reasonable mining conservation and environmental protection standards.

c. Set refusal prices that will assure a fair market value return from any leasing of Federal oil shale.

d. "Block-up" private and Federal lands.

The fiscal year 1969 budget provides for acceleration and strengthening of geological investigation activities.

2. Conduct adequate experimentation to develop the information and Government capability necessary to estimate the economics of mining, retorting, and refining so that the value of the resource in place can be estimated and refusal prices can be set.

The fiscal year 1969 budget provides initial financing to begin a more intensive study of the economic potential for extraction of minerals from shale -- an area where little previous work has been done and which is of current interest, particularly with reference to dawsonite. The development of an economically feasible technology for production of alumina from oil shale could materially change overall processing costs with a corresponding impact on resource values.

3. Promote active investigation and development of new technology so that costs of shale-oil production can be reduced. The research program should emphasize the kind of technology that can increase the value of the deep, thick seams of the Piceance Creek Basin, which are largely Government-owned. Development of the "cut-and-fill" mining method is an example of potential new technology that should be explored.

E. Alienation of the oil-shale resources

A major finding of this study is that it has been economic and technologic factors rather than the availability of land that have held back shale-oil development. There are large blocks of private lands, with clear title, that are particularly well suited for the most advanced oil-shale technology. Without title clarification, Government ownership of land of this type in the Piceance Creek Basin is limited (about 1 percent) in blocks large enough for production leasing, excluding the Naval oil-shale reserve. Nearly 20 percent of the oil-shale lands in the Piceance Creek Basin are in private ownership, but such ownerships may not be by those firms having the technology, financial resources, and need for commercial production.

This study indicates that the value of the resource in place now is small, and will remain so until new technology has been developed and proved. Industry, if it purchases the resource subject to the development of improved technology in the future, probably would discount its bid at the rates it uses for alternative delayed return investment opportunities. Since this could reduce the bonus bids, the Government should alienate little of its holdings until improved technology is developed or shown to be available by bids of appropriate size.

(1) Research agreements

It is in the Government's interest to encourage industry to make sufficient research expenditures that will lead to improved technology which will make oil-shale utilization more economically attractive, since under these circumstances the Government-owned resource would achieve a substantial actual value. Adhering to this principle, the Department of the Interior should take the following steps:

(a) Land and oil-shale resource

Where the research primarily requires the use of oil-shale land, such as for in situ retorting or mining technology experiments, the Government could negotiate individual agreements with firms needing such research sites. Advance public notice would be given for all noncompetitive research agreements. All applications or proposals for research agreements should clearly state both the minimum acreage and shale resource required. The maximum amount of shale resource for any single negotiated agreement would be limited to not more than 5 percent of the estimated amount of shale (equivalent to approximately 25 million bbls.) that would be required to support a full production plant. Such agreements would be limited in tenure and nature, would commit only the resource immediately required, would require payment of an appropriate amount considering the fair market value of the shale resource and for the land use privilege and would not give preference for subsequent production leasing. If a larger shale commitment is necessary, it would be obtained by competitive bidding procedures. Subsequent production leasing would be on the basis of competitive bidding.

(b) Oil shale resource only

For those who wish to do surface retorting experiments and do not have shale resources reasonably available, the Government could supply the oil shale, if available, at a suitable charge; in no case less than the cost of supplying it. This could lower the research cost to the purchaser as the investment in a mine to provide oil shale for experimental retorting could be as high as $3 to $4 million and might have to be duplicated by each industrial firm requiring oil shale for retorting experiments. Purchasing oil shale from the Government would eliminate duplication of this investment. Moreover, any experimental retort could be located where water, other utilities, and labor would be available at lowest cost.

(c) Patent policy

The Government would not be funding the research although Government resources would be used. Thus, both industry and the Government would be making a contribution to the research. In these circumstances, and consistent with the President's Patent Policy Statement of October 10, 1963, the Government should require licensing of resultant patents and also of the necessary background patents to everyone at reasonable royalties. The agreements also should contain appropriate requirements covering such matters as timely disclosure and availability of information developed in the course of the research, access to the research sites by Government personnel, and background data.

(2) Leasing

To assure that successful research resulting from such cooperative efforts will be used to establish commercial plants, to encourage research investments, and to assure that Federal oil-shale resources will be available at fair market value when needed, the Department of the Interior should establish and announce a policy that competitive leases will be offered from time to time on the basis of demonstrated production demand consistent with obtaining fair market value return to the Government and optimum resource utilization. These leases should be on a competitive basis with terms and conditions that will, among other requirements, avoid speculation and assure that timely commercial development is undertaken. It is only through such offerings that the industry could recover its research investments and that the public, as resource owner, can realize the economic benefits of an enhanced resource value. Those who have developed suitable technology should be able to bid successfully for such leases, or if they are not successful bidders, they still would have the opportunity to realize a return on their research investment through licensing to others at reasonable royalties.

(a) Test leases

There may be proprietary technology available that could make test leasing desirable for both thick and thin shale formations. Because the Government owns much of the thick, deep beds of the Piceance Basin, those with advanced technology to exploit this type of deposit might not be able to use their knowledge for commercial production without leases being offered. Moreover, some firms do not have sufficient oil-shale holdings and may wish to initiate a commercial venture using conventional technology in the thinner shale beds. To test the market, therefore, the Department should offer two competitive leases with sufficient oil shale to satisfy the requirements of a 35,000 to 50,000 barrel-per-day plant for the time required to amortize the investment (20 to 30 years). One lease would be in the thick beds and one in the thin formation most amenable to conventional mining and retorting. In this way, the Government would be able to test the market potential of both types of shale deposits.

Since the Mineral Leasing Act of 1920 raises problems in the development of an appropriate oil shale leasing program, test leases should be offered with an explicit understanding that they will not establish a precedent for future leasing. To the maximum extent possible, the test leases should attempt to mirror what this study shows to be reasonable lease methods and terms.

Test leases should be offered under such conditions so that it would not be profitable to hold the land for speculative purposes. A delayed payment, bonded-bonus bid, could be used. The delayed bonus would permit the potential lessee, who would not be able to exploit the resource for 4 to 5 years while the plant and mine were being constructed, to bid somewhat higher since he would not have to discount his bid for the unproductive early years. If, for these test leases, the royalties for 5 years were to be credited against the bonus (payment of which should be guaranteed by bond) it would be possible for a firm seriously interested in developing the resource to offer a high bonus. Under these conditions those who would bid primarily for speculation could not afford to do so. The type and amount of royalties would be specified in the invitations to bid.

(b) Production leasing policies

Based upon the findings of this report, it is estimated that it will be at least 5 years before significant production leasing of Federal lands would be possible or desirable even for the thin oil-shale formations which appear to be marginally attractive using existing retorting and mining systems. In the meantime, privately owned resources appear to be adequate to meet the production demand from oil shale. However, regulations and the related policies and procedures for such production leasing should be developed and publicly announced as soon as feasible so that the lack of availability of Federally owned resources at a fair market value return to the Government will not represent a barrier to development of an oil-shale industry.

Key conditions that should be included in production leasing to assure adequate protection of the public interest and, at the same time, fair and equitable treatment to the potential lessees include:

1. Competitive bidding (sealed or oral auction based upon anticipated competition). Initial leasing probably would be by sealed bid.

2. Advance resource identification financed by the Government and available to all potential bidders.

3. A leasing method that best assures fair market value return to the Government. (This probably should be a combination of cash bonus, possibly payable over time, and royalty payment with a fixed royalty on the total estimated quantity of shale sold or a declining royalty rate on some terminal portion of the resource to encourage optimum resource utilization.)

4. Refusal prices approximating fair market value return to the Government.

5. Fixed annual rental charges that are sufficiently high so as to avoid speculative holding of leases. (Subject to change in existing legislation.)

6. Multiple leases to individual lessees consistent with production needs and antitrust policies. (Subject to change in existing legislation.)

7. Mining and environmental controls combined with diligence and performance requirements that assure timely and effective resource utilization consistent with pollution avoidance, and appropriate protection of other resource and public values.

8. Lease period of sufficient tenure to permit a prudent operator adequate time for utilization of the resource leased to the extent it is available in minable commercial quantities. Appropriate renegotiation provisions effective at the end of the first 20 years and at periodic intervals thereafter should be included as there may be significant changes in technology, resource values, environmental factors, etc., that should be considered, particularly as they relate to the earlier production leases.

9. Transfer and exchange of leases subject to full compliance with all terms thereof. (Subject in part to change in existing legislation.)

10. To the extent that joint ventures inhibit competition, they should be discouraged. (The Department of Justice should be asked to consider what specific safeguards might be taken to assure competitive bidding for these resources.)

F. Mineral Leasing Act of 1920

In view of the vast potential of the Federally owned resource and the extended period over which it could be used, the provisions of the Mineral Leasing Act of 1920 should be reviewed further. Those provisions that present major policy or management issues should be analyzed, and considered for appropriate legislative changes. Legislative provisions should avoid serious impediments to leasing consistent with fair market value return to the Government; barriers to optimum use of the resource; conditions that prohibit reasonable opportunity for competition by private industry; and undesirable acquisition of oil-shale leases primarily for speculative purpose.

Since large Federal revenues probably will occur as a result of a commercial production program, a detailed analysis by the Department of the revenue sharing arrangements and earmarking provisions of the Act also is required with particular reference to the revenue distribution to States, the Reclamation Fund, and the Federal Treasury to determine the need for changes to assure appropriate provision for both national and local public interests.

This review should begin as soon as possible to assure sufficient time for orderly analysis, formulation of needed legislative changes, and for legislative review and action as a part of the preparation for the production leasing outlined in section E(2)(b) of this chapter. Early resolution of leasing and revenue distribution policies is essential so that uncertainties are eliminated by a clear statement of the public policies for commercial use of the resource. Undue delay could result in postponement of production leasing to avoid the establishment of undesirable precedents that could be difficult or impossible to change.

Appendix A

Quantity and Quality of Oil Shale Lands --

Federal and Non-Federal

Table A-1 Federal oil-shale lands
(including both clear and clouded title)

Item	Colorado	Utah	Wyoming	Total
Quantity of land				
Total oil-shale land, thousand acres	1,800	4,900	4,300	11,000
Federal oil-shale land, thousand acres [1]	1,420	3,780	2,670	7,870
Percent Federal land (of total)	79	77	62	72
Percent distribution, Federal land	16	45	39	100
Quality of Federal oil-shale lands				
Low grade or unappraised:				
Acres, thousand	570	2,130	1,500	4,200
Percent distribution	13	51	36	100
At least 15 ft of 15-25 gpt [2] shale:				
Acres, thousand	300	1,070	700	2,070
Percent distribution	15	51	34	100
At least 10 ft of over 25 gpt shale:				
Acres, thousand	600	600	400	1,600
Percent distribution	37	37	26	100
Quantity of shale oil in place - Federal lands [3]				
At least 15 ft. of 15-25 gpt shale:				
Shale oil, billion barrels	600	150	150	900
Percent distribution	66	17	17	100
At least 10 ft of over 25 gpt shale:				
Shale oil, billion barrels	390	70	20	480
Percent distribution	81	15	4	100
Total:				
Shale oil, billion barrels	990	220	170	1,380
Percent distribution	72	16	12	100

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[1] Largely clouded by unpatented mining claims.
[2] Gallons per ton.
[3] Data include some allocations from unappraised lands.

Table A-2- Non-Federal oil-shale lands - clear title [1]

Item	Colorado	Utah	Wyoming	Total
Quantity of land				
Total oil-shale land, thousand acres	1,800	4,900	4,300	11,000
Private oil-shale land, thousand acres	400	1,100	1,600	3,100
Percent private land (of total)	21	23	38	28
Percent distribution, non-Federal land	13	35	52	100
Quality of private oil-shale lands				
Low grade or unappraised:				
Acres, thousand	165	640	890	1,695
Percent distribution	10	38	52	100
At least 15 ft of 15-25 gpt [2] shale:				
Acres, thousand	80	320	440	840
Percent distribution	10	38	52	100
At least 10 ft of over 25 gpt shale:				
Acres, thousand	170	170	260	600
Percent distribution	28	28	44	100
Quantity of shale oil in place--private lands				
At least 15 ft of 15-25 gpt shale:				
Shale oil, billion barrels	130	40	80	250
Percent distribution	52	16	32	100
At least 10 ft of over 25 gpt shale:				
Shale oil, billion barrels	80	20	10	110
Percent distribution	73	18	9	100
Total:				
Shale oil, billion barrels	210	60	90	360
Percent distribution	58	17	25	100

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[1] Indian and State lands are included in data shown.

[2] Gallons per ton.

Table A-3 Federal oil-shale lands - clouded title

Item	Colorado	Utah	Wyoming	Total
Quantity of land				
Total Federal lands, thousand acres	1,420	3,780	2,670	7,870
Land with unpatented mining claims:				
Old claims, prior to 1966, thousand acres	400	2,600	2,200	5,200
New claims, 1966, thousand acres	700	400	400	1,500
Total with claims, thousand acres	1,100	3,000	2,600	6,700
Percent of Federal land with claims	78 1/	79	97	85
Quality of lands with unpatented claims				
Low grade or unappraised:				
Acres, thousand	500	1,700	1,400	3,600
Percent distribution	14	47	39	100
At least 15 ft of 15-25 gpt 2/ shale:				
Acres, thousand	200	800	700	1,700
Percent distribution	12	47	41	100
At least 10 ft of over 25 gpt shale:				
Acres, thousand	500	500	400	1,400
Percent distribution	36	36	28	100
Quantity shale oil in place, unpatented mining claims 3/				
At least 15 ft of 15-25 gpt shale:				
Shale oil, billion barrels	500	100	100	700
Percent distribution	72	14	14	100
At least 10 ft of over 25 gpt shale:				
Shale oil, billion barrels	320	50	20	390
Percent distribution	82	13	5	100
Total:				
Shale oil, billion barrels	820	150	120	1,090
Percent distribution	75	14	11	100

1/ Ninety-five percent of lands in Piceance Creek Basin, Colorado, have unpatented mining claims.

2/ Gallons per ton.

3/ Data include some allocations from unappraised lands.

Appendix B

Method Used in Calculating Present Worth of the Resource to the Owner.

A. Method of calculation

A conventional discounted cash flow format is used. Capital expenditures are shown in the years in which the outlays are made. It has been assumed for the purpose of these calculations that the resource was purchased one year before construction of the plant was started. Cash flow is defined as revenue minus operating expenses and income taxes. Cash flow can also be defined as net income plus depreciation and depletion. This calculation is shown in Table B-1.

The more familiar calculation in which a return is figured each year on the outstanding capital investment, yields the same results as the discounted cash flow method. This calculation is shown in Table B-2.

All monetary values in the calculations are in terms of 1967 constant dollars and a construction period of two years is allowed prior to initial operation of a plant.

All plants are presumed to operate for 20 years. The oil shale mine is depreciated at 10 percent per year for income tax purposes. A mine is assumed to have a useful life of 10 years and, therefore, a second mine would be opened for the second ten years. The capital expenditure for this second mine is shown as being made in years 11 and 12. The retorts and refineries are depreciated over 16 years for income tax purposes (based on IRS regulations) but are assumed to have a useful life for the full 20 years of the operation.

Table B-1 - Discounted cash flow computations (at 12 and 20 percent discount rates)--first generation retort with room-and-pillar mine

(Thousand of dollars)

Year	Item	Capital [1] expenditures (Col. 1)	Cash flow [2] @ $3.69/bbl. revenue (Col. 2)	Net cash flow (Col. 1+2)	Discount Coefficients		Present value of net cash flow	
					@ 12 percent	@ 20 percent	12 percent	20 percent
1	Mine and plant capital expenditure	18,741	------	-18,741	0.893	0.833	-16,736	-15,611
2		99,277	------	-99,277	.797	.694	-79,124	-68,898
3	Working capital expenditure	14,710	19,455	+ 4,745	.712	.579	+ 3,378	+ 2,747
4		------	19,455	19,455	.636	.482	12,373	9,377
5		------	19,455	19,455	.567	.402	11,031	7,821
6		------	19,455	19,455	.507	.335	9,864	6,517
7		------	19,455	19,455	.452	.279	8,794	5,428
8		------	19,455	19,455	.404	.233	7,860	4,533
9		------	19,455	19,455	.361	.194	7,023	3,774
10		------	19,455	19,455	.322	.162	6,265	3,152
11	Second mine capital expenditure	2,886	19,455	16,569	.287	.135	4,755	2,237
12		15,289	19,455	4,166	.257	.112	1,071	467
13		------	19,455	19,455	.229	.093	4,455	1,809
14		------	19,455	19,455	.205	.078	3,988	1,517
15		------	19,455	19,455	.183	.065	3,560	1,265
16		------	19,455	19,455	.163	.054	3,171	1,051
17		------	19,455	19,455	.146	.045	2,840	875
18		------	19,455	19,455	.130	.038	2,529	739
19		------	18,100[3]	18,100	.116	.031	2,100	561
20		------	18,100	18,100	.104	.026	1,882	471
21		------	18,100	18,100	.093	.022	1,683	398
22		------	18,100	18,100	.083	.018	1,502	326
23	Recovery of working capital	------	14,710	14,710	.074	.015	1,088	221
	Total	-150,903	+398,390	+247,487			+5,354	-29,222

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[1] Does not include lease bonus.

[2] Revenue minus operating costs and income taxes.

[3] Decrease of cash flow due to increase in tax liability at end of 16-year (of operation)depreciation period allowed (for tax purposes) on retort and refinery by Internal Revenue Service.

Table B-2. - Present value (at 12 percent discount rate) of cash flow after repayment of investment at 12 percent return on outstanding balance --first generation retort with room-and-pillar mine

(Thousands of dollars)

Year	Capital Expenditures	Cash Flow @ $3.69/bbl. revenue	Return on Investment @ 12 percent	Available for repayment of Investment	Investment Outstanding (beginning of year)	Cash flow after investment curtailment	Present Value of net cash flow @ 12 percent
1	18,741	------	------	------	-------	------	------
2	99,277	------	2,249	-2,249	18,741	------	------
3	14,710	19,455	14,432	5,023	120,267	------	------
4	------	19,455	15,596	3,861	129,994	------	------
5	------	19,455	15,131	4,324	126,093	------	------
6	------	19,455	14,612	4,843	121,769	------	------
7	------	19,455	14,031	5,424	116,926	------	------
8	------	19,455	13,380	6,075	111,502	------	------
9	------	19,455	12,651	6,804	105,427	------	------
10	------	19,455	11,835	7,620	98,623	------	------
11	2,886	19,455	10,920	8,535	91,003	------	------
12	15,289	19,455	10,242	9,213	85,354	------	------
13	------	19,455	10,972	8,483	91,430	------	------
14	------	19,455	9,954	9,501	82,947	------	------
15	------	19,455	8,814	10,641	73,446	------	------
16	------	19,455	7,537	11,918	62,805	------	------
17	------	19,455	6,106	13,349	50,887	------	------
18	------	19,455	4,505	14,950	37,538	------	------
19	------	18,100	2,711	15,389	22,588	------	------
20	------	18,100	864	7,199	7,199	10,037	1,044
21	------	18,100	------	0	0	18,100	1,683
22	------	18,100	------	0	0	18,100	1,502
23	------	14,710	------	0	0	14,710	1,088
							5,317

In the nuclear in-situ case, the recovery plant and the initial chimneys created by the nuclear detonation are depreciated over twenty years. The cost of creating subsequent chimneys is treated as an operating cost. The refinery for this case, as in the others, is depreciated over 16 years and operated for 20 years.

In the conventional mining and retorting cases, depletion for income tax purposes is figured at 15 percent of the value of the mined oil shale not to exceed 50 percent of income before depletion and taxes. In the nuclear in-situ case, for analysis purposes depletion has been calculated at 15 percent of the value of the product as it is recovered at the chimney. Here, too, the 50 percent limitation was applied.

For purposes of the depletion computation, values must be developed for the intermediate products - mined rock, or crude oil in the case of the nuclear in-situ operation. In each case, this was done by determining the sum of the charges (depreciation + operating cost + income tax + return on capital) against the mining or the nuclear retorting as compared to the total operation, and dividing the revenue between the operations in this same proportion. Because income tax and the apportionment of revenue are mutually dependent, the values were calculated by a series of successive approximations.

Resource value computations were made at two discount rates, 12 percent and 20 percent. The 20 percent discounted cash flow (DCF) rate of return after taxes was selected since: (1) The technology to be used in the first plants has been extrapolated beyond existing data;

(2) industry believes that the first investments in a new product line require this amount of return, and (3) the first plants are expected to be obsolete in a very short period of time. The initial shale oil plant at each new stage of technology would require this rate. A 12 percent DCF rate has been taken as the return after taxes required on capital in proven mining and manufacturing endeavors.[1] The second and subsequent plants in each technology would require the expectation of this rate of return.

Computations were made at two or more price levels in order to plot curves showing the effect of price on net present values.

The sequence of computations for each case was thus:

1. Select a price level.
2. Determine the portion of revenue attributable to the operations up to the point where percent depletion is calculated.
3. Calculate depletion allowance and Federal income tax.
4. Set out the time sequence of capital expenditures and cash flow over the period of construction and 20 years of operation.
5. Discount these cash flows at 12 percent. Add to obtain present value. Repeat for 20 percent.

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[1] The Financial Feasibility of Capital Expenditures for Oil Shale Development 1915-1920 and 1966, Solomon, Ezra, Special Study for the Department of the Interior, 1967, Stanford University, 73 pages.

6. Select new price level and repeat from Item 2.

No credit has been taken for salvage values in these calculations nor has any cost been included for research and development.

Table B-1 shows the cash flow values for the first generation retort with room-and-pillar mining. Figures B-1 to B-5 show the curves plotted from similar calculations in each of the five cases.

The price at which these curves cross the zero present value line is the price necessary to yield the required rate of return. If output of the plant can be sold for more than this "minimum-necessary" price, the additional revenue would be available to pay for the resource. If it is paid as the oil is produced, it is a royalty payment. If it is paid as a lump sum, it is a bonus payment. When a bonus payment is made, the same rate of return will be expected on this outlay as on the capital outlay for plant facilities. This bonus outlay will be expected to generate income, and income taxes will have to be paid on this income. The equivalency between bonus and royalty is as follows:

Bonus = Present value of (royalty value - income tax liability generated by royalty).

Table B-3 shows, for each of the technologies being evaluated, what the bonus or resource value is if the plant product can be sold for 1 cent per barrel more than the revenue needed to yield the 12-percent and 20-percent returns. Having these "one-cent" royalty values, it is a simple matter to convert to any assumed selling price or royalty.

In Table B-4, a selling price in Colorado for shale oil of $3.08 is used. To this shale oil price must be added the by-product value to

FIG. B-1

PRESENT VALUE OF NET CASH FLOW VS PRICE OF SHALE OIL AND BYPRODUCTS

FIRST GENERATION RETORT ROOM-AND-PILLAR MINE

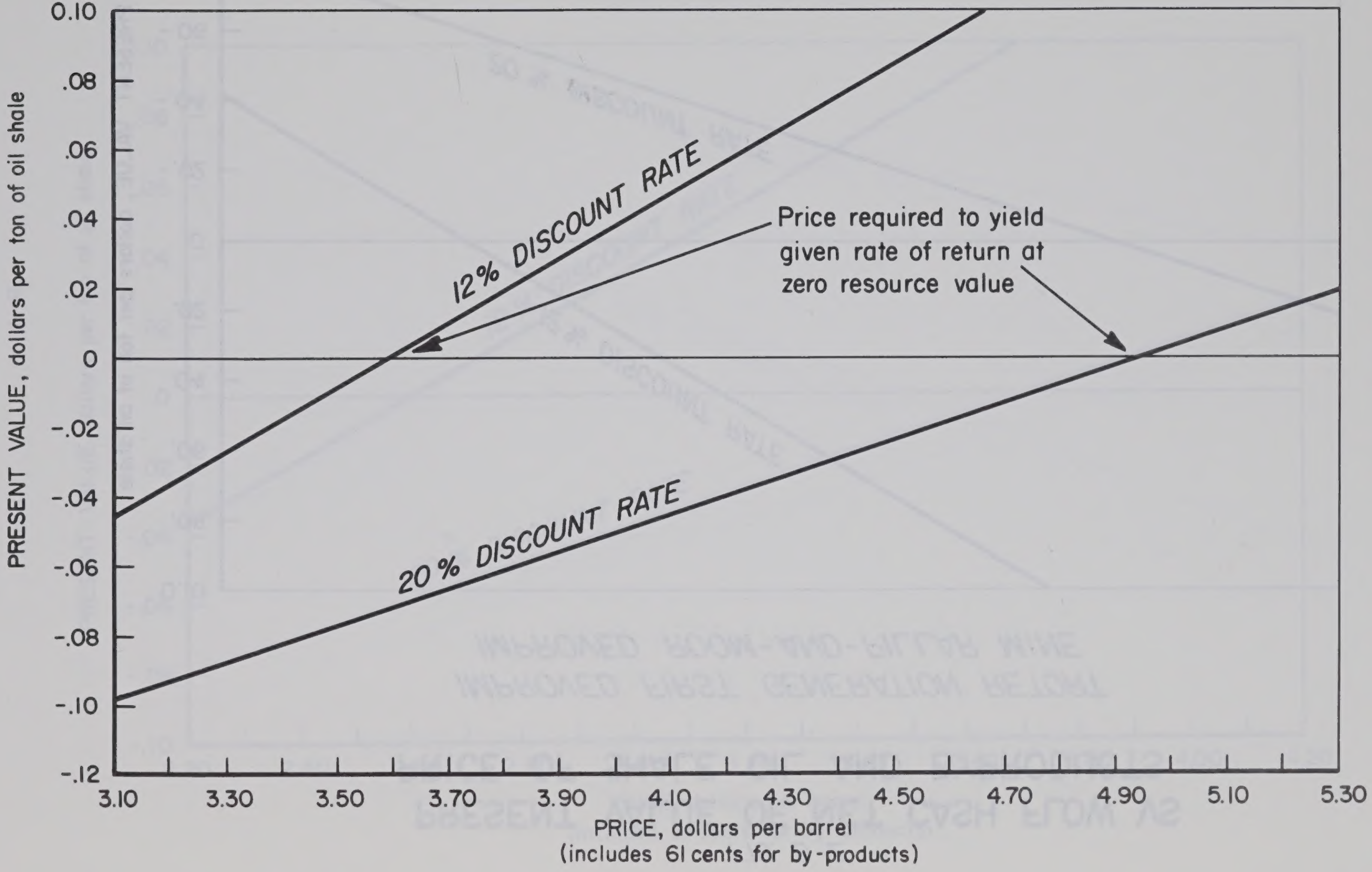

FIG. B-2

PRESENT VALUE OF NET CASH FLOW VS PRICE OF SHALE OIL AND BYPRODUCTS

IMPROVED FIRST GENERATION RETORT
IMPROVED ROOM-AND-PILLAR MINE

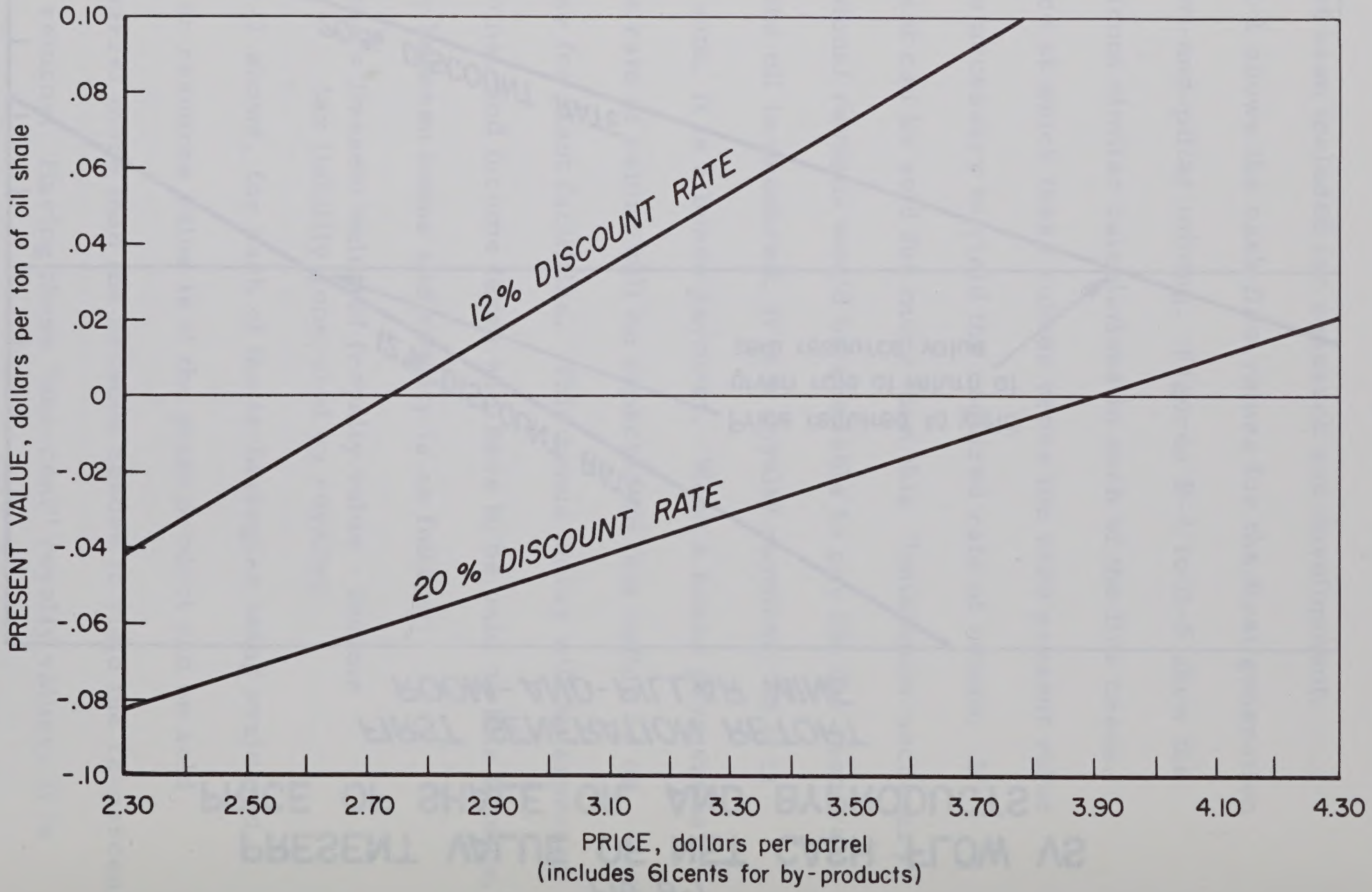

FIG. B-3

PRESENT VALUE OF NET CASH FLOW VS PRICE OF SHALE OIL AND BYPRODUCTS

IMPROVED FIRST GENERATION RETORT
IMPROVED OPEN PIT MINE

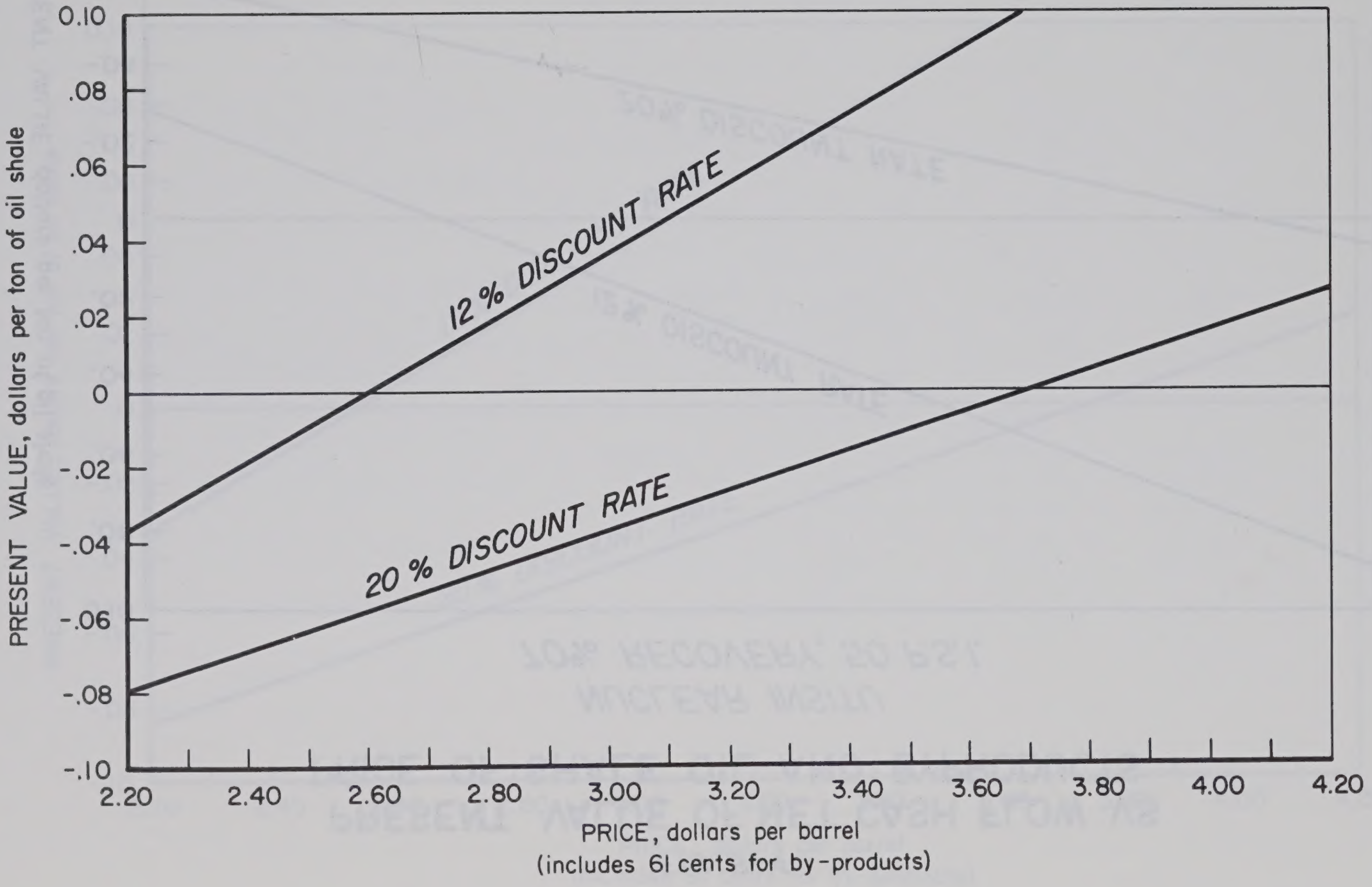

FIG. B-4

PRESENT VALUE OF NET CASH FLOW VS PRICE OF SHALE OIL AND BYPRODUCTS

NUCLEAR INSITU
70% RECOVERY, 50 P.S.I.

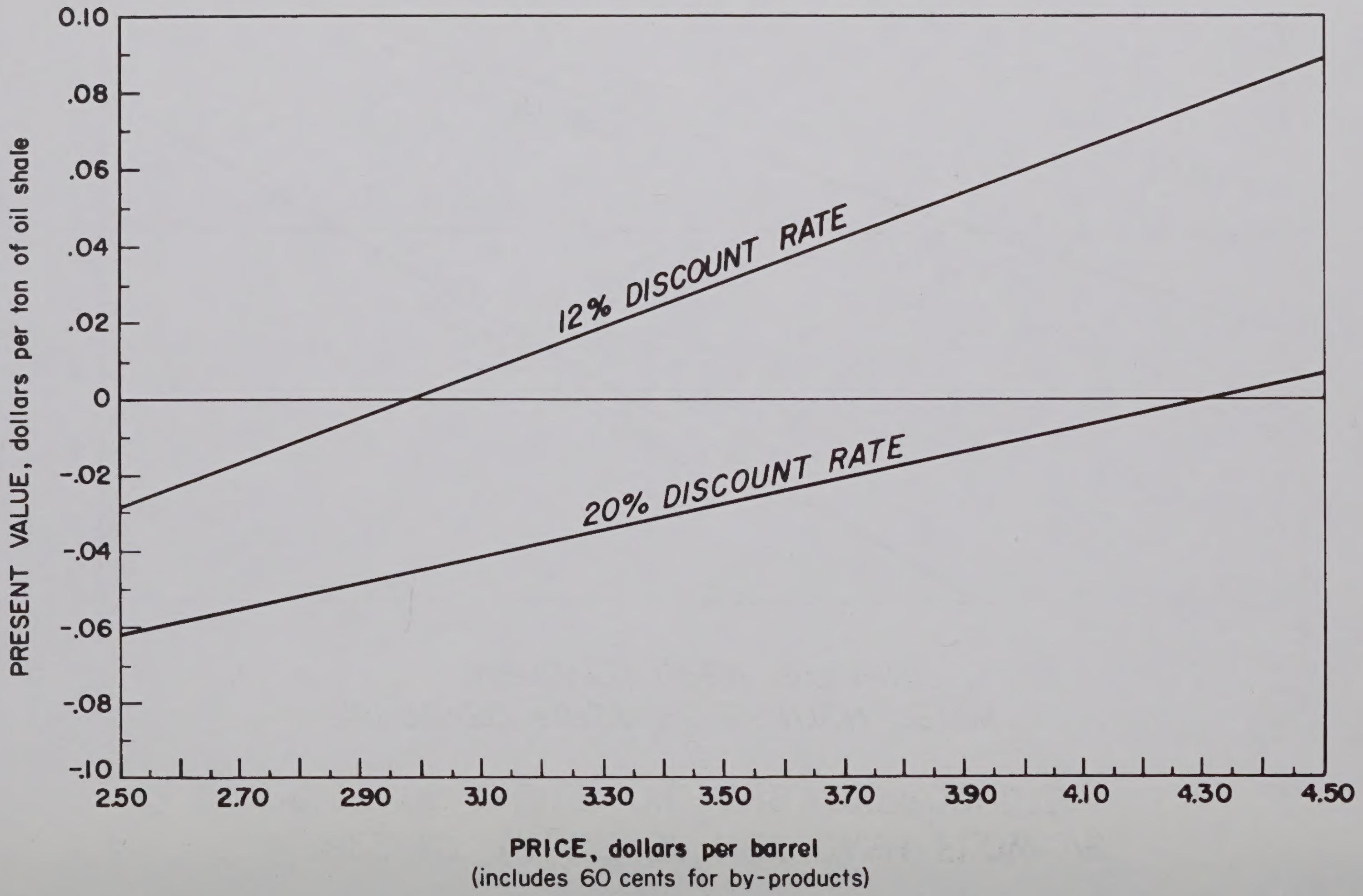

FIG. B-5

PRESENT VALUE OF NET CASH FLOW VS PRICE OF SHALE OIL AND BYPRODUCTS

SECOND GENERATION RETORT
CUT-AND-FILL MINE

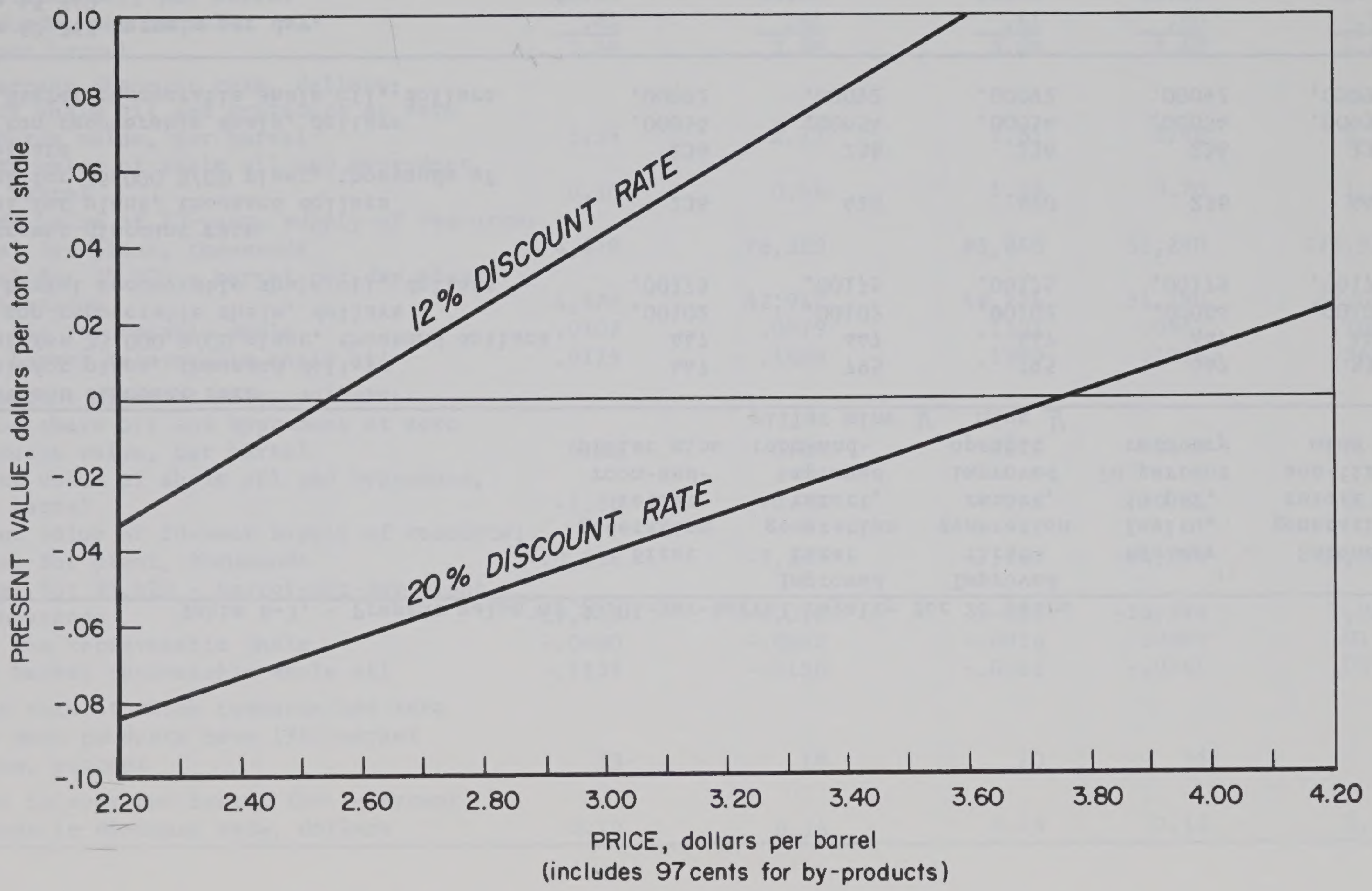

Table B-3. - Present value of $0.01-per-barrel royalty for 20 years

	First generation retort room-and-pillar mine	Improved first generation retort, improved room-and-pillar mine 1/	Improved first generation retort, improved openpit mine 1/	Nuclear Insitu, 50 psi, 70 percent recovery	Second generation retort cut-and-fill mine 2/
A. At 12 percent discount rate					
1. Total for plant, thousand dollars	447	795	795	447	837
2. Total for 35,000 B/CD plant, thousand dollars	447	447	447	447	447
3. Per ton recoverable shale, dollars	.00102	.00102	.00102	.00064	.00107
4. Per barrel recoverable shale oil, dollars	.00175	.00175	.00175	.00175	.00175
B. At 20 percent discount rate					
1. Total for plant, thousand dollars	236	420	420	236	442
2. Total for 35,000 B/CD plant, thousands of dollars	236	236	236	236	236
3. Per ton recoverable shale, dollars	.00054	.00054	.00054	.00034	.00057
4. Per barrel recoverable shale oil, dollars	.00092	.00092	.00092	.00092	.00092

1/ Plant size 62,265 barrels per day.
2/ Plant size 65,540.

Table B-4. - Summary value statistics

	First generation retort room-and-pillar mine	Improved first generation retort, impr. room-and-pillar mine	Improved first generation retort, improved open mine	Nuclear in situ, 50 psi,70 percent recovery	Second generation retort cut-and-fill mine
A. Size of plant:					
Semirefined oil, barrels-per-day	35,020	62,265	62,265	35,020	65,540
Shale for 20 years, million tons	440	780	780	700	780
B. Market value of product, dollars:					
Semirefined oil, per barrel	$3.08	$3.08	$3.08	$3.08	$3.08
Byproducts, per barrel	.61	.61	.61	.60	.97
Total, per barrel	3.69	3.69	3.69	3.68	4.05
C. At 12-percent discount rate, dollars:					
Cost of shale oil and byproduct at zero resource value, per barrel	3.59	2.73	2.61	2.98	2.55
Royalty value of shale oil and byproduct, per barrel	0.10	0.96	1.08	0.70	1.50
Present value of 20-year, supply of resource:					
Total for plant, thousands	4,470	76,320	85,860	31,290	125,550
Total for 35,020 - barrel-per-day plant, thousands	4,470	42,912	48,276	31,290	67,050
Per ton recoverable shale	.0102	.0979	.1102	.0447	.1605
Per barrel recoverable shale oil	.0175	.1680	.1890	.1224	.2625
D. At 20-percent discount rate, dollars:					
Cost of shale oil and byproduct at zero resource value, per barrel	4.95	3.86	3.72	4.29	3.75
Royalty value of shale oil and byproduct, per barrel	-1.26	-0.17	-.03	-0.61	0.30
Present value of 20-year supply of resource:					
Total for plant, thousands	-29,736	-7,140	-1,260	-14,396	13,260
Total for 35,020 - barrel-per-day plant, thousands	-29,736	-4,012	-708	-14,396	7,080
Per ton receoverable shale	-.0680	-.0092	-.0016	-.0207	.0171
Per barrel recoverable shale oil	-.1159	-.0156	-.0028	-.0561	.0276
E. Discount rate at which resource has zero value when products have 1967 market value, percent	13	19	20	16	22
F. Increase in cost per barrel for 1-percent increase in discount rate, dollars	0.16	0.15	0.15	0.16	0.15

obtain total market value of product. The royalty value is obtained by subtracting from this the product price that gives zero resource value. This royalty value is different in each of the technologies being considered. By multiplying these royalty values by the "one-cent" values from Table B-3 the present values of the resource are obtained for each case. The present values are shown in terms of:

1. The total value of the resource that is necessary to support a plant of the reported size for 20 years;

2. The total value of the resource that is necessary to support a 35,000 barrel per day plant of semirefined oil for 20 years (to permit comparison between similar sized plants);

3. The present value of the resource per ton of recoverable oil shale;

4. The present value of the resource per barrel of recoverable oil.

In addition, Table B-4 shows the discount rate, or the DCF rate of return obtained when products are sold at the 1967 market price and the resource is assigned a zero value. How much a 1-percent change in rate of return affects the cost per barrel is also shown.

In Figures B-1 to B-5, the vertical axis is "present value of net cash flow". These figures which are obtained from the cash flow calculation are not the same as "resource value." Net cash flow is money available after payment of operating expenses and income taxes. The "present value of net cash flow" figures on these charts resulted from the assumption of zero resource value and thus include higher income tax payments than would accrue if a bonus were paid for the resource.

B. Result of cash flow calculations - excluding social benefits and costs

1. 1972 technology.

The calculations show that an experimental plant requiring 20 percent DCF rate of return would need to sell its semi-refined shale oil at $4.34 per barrel, after byproduct credit ($4.95 - 0.61 = $4.34) (resources free). With a value of semi-refined shale oil of $3.08 per barrel, the price competitive with natural crude oil, a 35,000 B/CD semi-refined shale oil plant would need a $30 million subsidy (resources free). The subsidy is equivalent to 6.8 cents per ton of recoverable shale.

If the experimental plant proved the technology, subsequent plants might expect only a 12-percent DCF rate of return. With this return a plant would be able to sell shale oil at $2.98 per barrel (resources free). If it could sell semi-refined shale oil at $3.08 per barrel, it could afford to pay $4.5 million for a 20-year supply of oil shale. This value is equivalent to 1.0 cent per ton of recoverable oil shale and is calculated as of 1970, at the assumed start of construction of a plant to be operable in 1972. If the operator bid on this resource in 1968, its value would be $3.6 million which is the 1970 value discounted at 12 percent per year to 1968.

2. 1976 technology.

Three of the 1976 technologies were evaluated in order to select the one to be incorporated in this study. Nuclear in-situ at 50 psi air pressure and 70 percent recovery of the shale oil would produce semi-refined shale oil at $2.38 per barrel using a 12-percent DCF (resources free). This appears to be less economic than either of the other two 1976 technologies. The improved first-generation retort with improved open pit mining would produce a semi-refined shale oil at $2.12 per barrel. Both of these prices are on the basis of 12 percent DCF and resources free.

In view of the additional overburden haulage costs that would be encountered in open pit mining, which are not included in the cost estimates, and the social costs that open pit mining causes, improved room-and-pillar mining with the improved first generation retort was used as the preferred 1976 technology.

An experimental plant using improved room-and-pillar mining and the improved first-generation retort would need to sell semi-refined shale oil at $3.25 per barrel to make 20 percent DCF (resources free). If the semi-refined shale oil could be sold at $3.08 per barrel, the shale resource to support a 52,000 B/CD plant for 20 years would have a negative value in 1974 (operation in 1976) of $4.0 million or--0.9 cent per ton of recoverable shale. This implies that a subsidy would be required if a 20 percent DCF were expected.

Once the technology is proven, an improved first-generation plant with improved room-and-pillar mining would require a 12 percent DCF and have a semi-refined shale oil cost of $2.12 per barrel (resources free). If semi-refined shale oil could be sold at $3.08 per barrel, the resource to support a 52,000 B/CD plant of semi-refined shale oil for 20 years would have a value in 1974 of $76.3 million or 9.8 cents per ton of recoverable shale. The value of the resource in 1968, with operation in 1976, would be $38.7 millinn.

3. 1980 technology.

By 1980, it is assumed that a second generation retort with a cut-and-fill mine could be in operation. The first experimental plant, in order to make a 20 percent DCF, would have a semi-refined shale oil cost of $2.78 per barrel (resources free). If it could sell semi-refined shale oil at $3.08 the resource to support a 65,000 B/CD plant of semi-refined shale oil for 20 years would have a value of $13.3 million or 1.7 cents per ton of recoverable shale.

Subsequent plants of this type making 12 percent DCF would have a semi-refined shale oil cost of $1.58 (resources free). If semi-refined shale oil were sold at $3.08 the resource to supply the 65,000 B/CD plant of semi-refined shale oil for 20 years would have a value in 1978 of $125.6 million (plant operation in 1980). The value of the resource in 1968 for a 1980 operation would be $40.4 million.

These three phases of technology can be summarized in terms of the cost of producing shale oil, i. e., the selling price required for shale oil to yield zero present value at the specified DCF rate of return when there is no charge for the resource,

	Selling price of shale oil Dollars per barrel		
	1972	1976	1980
Experimental plant (20 percent DCF)	4.34	3.25	2.78
Production plant (12 percent DCF)	2.98	2.12	1.58

or alternatively in terms of the value of the resource to support a 35,000 B/CD plant of semi-refined shale oil for 20 years if it were expected to sell at a $3.08 per barrel and to yield 12 percent DCF.

	Present value of resource at start of construction 1/ (million dollars)		
	1970	1974	1978
Production plant	4.5	42.9	67.1

C. Timing of lease sales

Table B-5 shows the present value of the oil shale resource to support a plant at the time construction would begin and also as of 1968. If a bidder obtains a lease in 1968 for use at some later date, he foregoes

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1/ 35,000 barrels-per-day of semi-refined shale oil.

Table B-5--Benefit to Government of holding resource until technology is available

Year	First-generation retort room-and-pillar mine	Improved first-generation retort, improved room-and-pillar mine	Improved first-generation retort, improved openpit mine	Nuclear in situ, 50 psi, 70-percent recovery	Second-generation retort, cut-and-fill mine
	Size of Plant B/CD				
	35,000	62,000	62,000	35,000	65,500
	Present value of 20-year supply of recoverable resource, thousands of dollars				
1978	------	------	------	------	125,550
1974	------	76,320	85,860	31,290	-------
1970	4,470	------	------	------	-------
1968 (12 percent DCF)	3,563	38,694	43,531	15,864	40,427
	Size of Plant B/CD				
	35,000	35,000	35,000	35,000	35,000
	Present value of 20-year supply of recoverable resource, thousands of dollars				
1978	------	------	------	------	67,050
1974	------	42,912	48,276	31,290	------
1970	4,470	------	------	------	------
1968 (12 percent DCF)	3,563	21,756	24,476	15,864	21,590

the opportunity to earn a return on those funds for the intervening years and would discount his offer by 12 percent per year for that period.

Unless the Federal Government utilizes the money obtained from early lease sales for programs that have a better than 12 percent internal rate of return, it would be to the advantage of the Government to hold shale lands until the lessee was ready to begin construction.